EAST COAST NATURAL GAS MARKET STUDY

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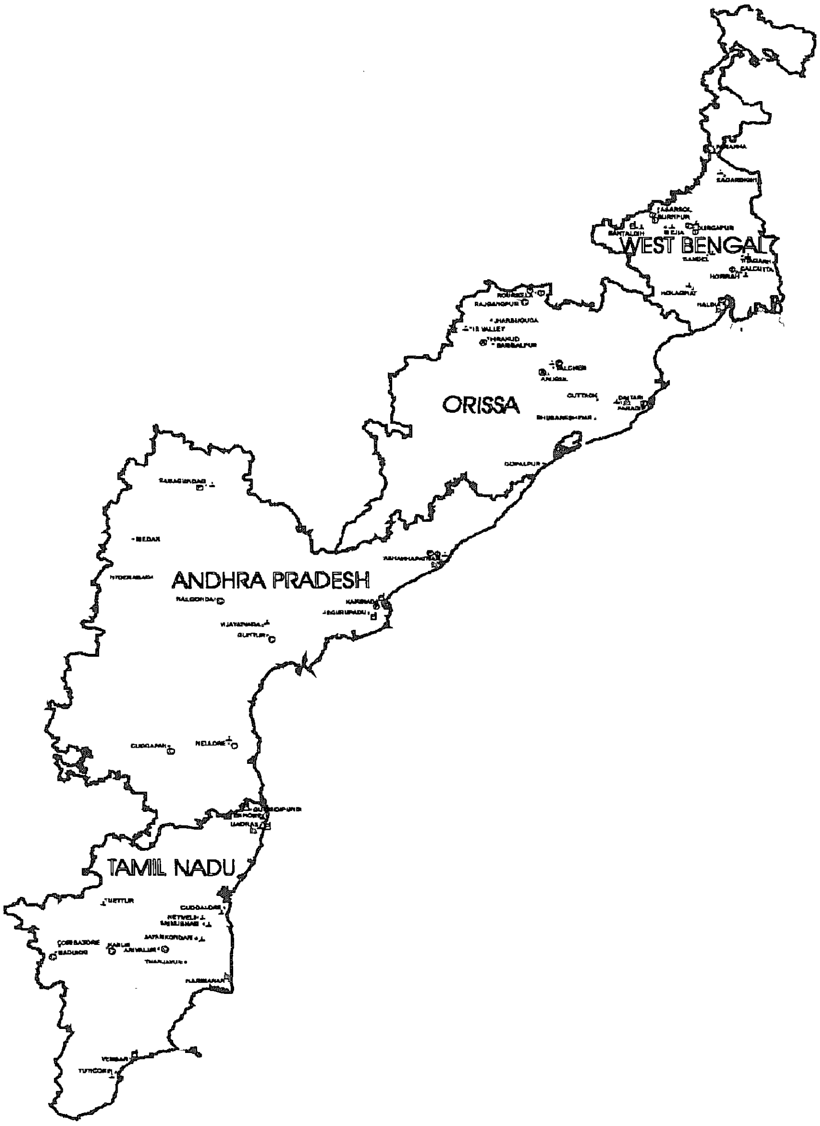

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GLOSSARY

BCM	Billion Cubic Metres
BICP	Bureau of Industrial Costs & Prices
BPCL	Bharat Petroleum Corporation Limited
BSES	Bombay Suburban Electric Supply Corporation Limited
C&F	Cost and Freight
CARG	Compounded Annual Rate of Growth
CEA	Central Electricity Authority
CIL	Coal India Limited
CNG	Compressed Natural Gas
COPE	Crude Oil Process Equalisation
DGH	Directorate General of Hydrocarbons
EOU	Export Oriented Unit
EPA	Environment Protection Act
FIPB	Foreign investment Promotion Board
FO	Fuel Oil
FSP	Freight Surcharge Pool
GDP	Gross Domestic Product
GJ	Giga Joule
GOI	Government of India
GRIDCO	Grid Corporation of Orissa
GT	Gas Turbine
GWh	Giga watt hour
HPCL	Hindustan Petroleum Corporation Limited
IGCC	Integrated Gassification Coal Combustion
IISCO	Indian Iron & Steel Company
IOC	Indian Oil Corporation
IPC	In Principle Clearance
IPP	Independent Power Producer
JV	Joint Venture
kcal	Kilo-calories
KL	Kilo litre
kV	Kilovolts
kVA	Kilovolt-ampere
kWh	Kilowatt hour
LHV	Low Heat Value
LNG	Liquefied Natural Gas
LOI	Letter of Intent
LPG	Liquefied Petroleum Gas
MCM	Million Cubic Metre
MMBtu	Million British Thermal Units
MMSCMD	Million Metric Standard Cubic Meters per Day

MMT	Million Metric Tons
mmtpa	Million Metric Tons per Annum
MOP	Ministry of Power
MT	Metric ton
MVA	Megavolt-ampere
MW	Megawatt
NG	Natural Gas
NLC	Neyveli Lignite Corporation
Nm^3	Normal metre cubed
NPC	Nuclear Power Corporation
NTPC	National Thermal Power Corporation
O&M	Operation & Maintenance
OCC	Oil Co-ordination Committee
ODA	Overseas Development Agency
OERC	Orissa Electricity Regulatory Commission
OIDB	Oil Industry Development Board
ONGC	Oil and Natural Gas Corporation
OPC	Oil Prices Committee
OSEB	Orissa State Electricity Board
PLF	Plant Load Factor
PPA	Product Price Adjustment / Power purchase agreement
PSU	Public Sector Undertaking
RoG	Rate of Growth
ROR	Rate of Return
Rs	Rupees
SCCL	Singareni Collieries Company Limited
SDP	State Domestic Product
SEB	State Electricity Board
SED	State Electricity Duty
SLF	System Load Factor
T&D	Transmission and Distribution
TCF	Trillion Cubic Feet
TEC	Techno-Economic Clearance
TEL	Tetraethyl Lead
tkm	ton-kilometre
TPA	Tons per annum
tpd	Tons per day
w.e.f.	with effect from
WBSEB	West Bengal State Electricity Board

CHAPTER 1
EXECUTIVE SUMMARY

1.1. POWER SECTOR

Electricity is legislated upon both by the Central, as well as the State governments. The Central Electricity Authority advises the Ministry of Power at the Centre, while at the state level, State Electricity Boards (SEBs) are statutory organisations looking after development of the power sector. Tariffs for purchase of power from private producers as well as for sale to ultimate consumers are set by the state governments in consultation with the SEB. The Central government has the final say in granting clearances for power projects in all cases, as it approves the fuel linkages.

Orissa has started the reform process and disbanded the erstwhile Orissa State Electricity Board (OSEB) into separate generation and transmission/distribution companies. Management contracts have also been awarded in three circles (Bhubaneshwar, Cuttack and Dhenkanal) for distribution to the Bombay Suburban Electric Supply Corporation Ltd. (BSES), a premier private sector electric utility in India, as a first step towards complete privatisation of distribution. The Orissa Electricity Regulatory Commission (OERC) has been set up in the state and charged with the responsibility of regulating the purchase, distribution, supply and utilisation of electricity, the quality of service, and the tariff and charges payable, keeping in view both the interest of the consumer as well as the suppliers.

All the four states are currently suffering from power shortages, with Tamil Nadu and Andhra Pradesh being the worst affected. West Bengal suffers from shortages even though its installed capacity is adequate to meet the demand because of two reasons. The first is that the transmission & distribution system in the state does not have the capacity to deliver power at places where it is needed. The other is that thermal power plants run at low PLFs for reasons other than the inadequate evacuation of power.

The deficit situation is likely to continue in the future also as can be seen from Table 1.1 which compares the expected installed capacity with the actual capacity needed.

In all the states, there exist a high level of cross subsidy in electricity prices across the sectors. Industrial consumers are charged higher per unit rates compared to the average cost of generation and supply, while electricity for all the other sectors is sold at a subsidised rate.

Table 1.1: Comparison of capacity requirement with expected capacity

(MW)

	Installed capacity required	Expected installed capacity	Surplus/Deficit
West Bengal			
2000	5084	8229	3145
2005	6891	10595	3704
2010	9971	10914	943
2015	14534	11311	(-)3223
Orissa			
2000	6549	5729	(-)820
2005	9683	10364	681
2010	15373	13050	(-)2323
2015	23527	15909	(-)7618
Andhra Pradesh			
2000	10698	7656	(-)3042
2005	15104	8747	(-)6357
2010	22256	9329	(-)12927
2015	32786	10418	(-)22368
Tamil Nadu			
2000	8741	8399	(-)342
2005	12520	9821	(-)2699
2010	18722	12909	(-)5813
2015	27546	16453	(-)11093

The average sector-wise tariff in 1995-96 for the three states along with the average cost of supply of power in US $/MMBtu, is given in Table 1.2.

Table 1.2: Average cost of supply and average electricity tariff (1995-96)

($/MMBtu)

State	Domestic	Commercial	Agriculture	Industrial	Avg. tariff	Supply cost
West Bengal	5.89	13.23	2.25	15.36	12.97	15.73
Orissa	7.12	9.21	4.19	14.51	11.03	10.71
Andhra Pradesh	7.53	14.14	0.62	17.35	10.58	12.65
Tamil Nadu	7.71	19.88	0.00	19.05	12.25	14.90

1.2. INDIGENOUS COAL

The prices of power grade coal are due to be completely decontrolled by the year 2000. In the meantime, the government has allowed the subsidiary coal companies of Coal India Limited to fix the price of power grade coals by themselves. These prices would be reviewed every six months by updating the cost indices as per the escalation formula contained in the 1987 report of the Bureau of Industrial Costs and Prices (BICP).

The study region accounts for about half of the total coal produced by Coal India Limited. The major coal demand in these states is in coal-fired generating stations and the iron & steel industry, though cement and fertiliser industries also have a share in the demand for coal.

1.3. HYDROCARBONS

India's hydrocarbon sector is dominated by the public sector undertakings. While ONGC and OIL are responsible for exploration and production, GAIL undertakes the transportation and marketing of the natural gas. The government has taken several steps in the recent past to restructure the hydrocarbon industry and remove the constraints in the functioning of the public sector undertakings, but there are still several issues such as the oil pool account deficit which require immediate attention.

Oil companies have an assured return on the capital employed due to the current pricing regime. However, the administered pricing regime has started undergoing some change as parallel marketing at market determined prices for kerosene, LPG, LSHS and lubricants has now been allowed.

A major gas pipeline in India is the 1800 km Hazira-Bijaipur-Jagdishpur (HBJ) gas pipeline system owned and operated by GAIL. As a part of its future activities, GAIL plans to construct an 1,820 km long gas pipeline of 35-40 cm diameter from Kandla, Okha/Sikka to Piyala.

It is difficult to make demand-supply estimates for Tripura for the year 2001-02, because no worthwhile estimates can be made in the absence of more firm information about additional customers. The production potential in Tripura has, however, been variously assessed as between 3 to 6 MMSCMD, subject to adequate exploration and development efforts, but investments on exploration and/or development would be linked to development of new demand and vice-versa. If we take in to account the possibility of gas demand in the power sector in Assam not materialising fully because of plant availability and energy demand problems, there is a potential for excess gas supply situation continuing in both Assam and Tripura.

Based on current proposals, West Bengal is the only state which is expected to have a significant demand for naphtha, reaching to 1.6 MMT/year by 2005. Of the other three states, Tamil Nadu has the maximum demand for naphtha, reaching to almost 0.6 MMT/year by 2015.

Orissa registers the highest growth for LPG, with an average annual growth rate of 7.67% between 2000 and 2015. West Bengal and Andhra Pradesh have similar rates of growth for LPG of around 5.5%, while Tamil Nadu's growth rate is only 2.89%.

Fuel oil demand grows at between 4 and 5% for West Bengal and Andhra Pradesh, while for Orissa and Tamil Nadu, the growth rate is restricted to 2.0-2.5%.

1.4. INDUSTRIAL SECTOR

The region comprising of West Bengal, Orissa and Andhra Pradesh is a major centre for iron & steel industries:- The Durgapur Steel Plant and the Indian Iron and Steel Company (IISCO) at Burnpur in West Bengal; the integrated Rourkela Steel Plant at Rourkela in Orissa; and the Vishakhapatnam Steel Plant at Vishakhapatnam in Andhra Pradesh. The region is expected to witness a growth of about 7.5% per year in the iron & steel sector.

Cement industries are mainly clustered in Andhra Pradesh and Tamil Nadu, while all four states host major fertiliser industries.

1.5. DOMESTIC SECTOR

The urban domestic sector consumes a large quantity of LPG which could be replaced by natural gas in those markets where a pipeline network is planned to meet power and industrial demand. The consumers would welcome piped supply of gas for cooking instead of having to rely on the often erratic supply of LPG cylinders.

1.6. SALES POTENTIAL FOR NATURAL GAS

Table 1.3 gives the sales potential of natural gas for all sectors in the study region.

The assumptions which have been made in calculation of the sales potential for natural gas are discussed below.

1.6.1. Power sector

The natural gas requirement has been derived from the installed capacities of the power stations located in the study area and expected to be based on gas or liquid fuels. This was done as power stations (utility owned or captive) using gas oil, fuel oil or naphtha can switch to using natural gas without major modifications, and it has been assumed that all power stations using these fuels would switch to gas if it were made available at a competitive price. In addition, it has been broadly assumed that one-third of the following would be amenable to using natural gas.

1. Any power plant owned by an Independent Power Producer (IPP) and due to come up after 2000. (These would need to redesign their plants to use gas turbines instead of steam turbines.)
2. All captive power plants located in the study area and due to come up after 2000.
3. Any deficit in installed capacity (beyond 2000).

Table 1.3: Natural gas sales potential in the study area

(MCM/year)

	2000	2005	2010	2015
WEST BENGAL				
Power	445	880	991	2245
Iron & Steel	34	41	50	61
Fertiliser	181	768	768	768
Cement	2	2	3	3
Domestic	418	607	751	927
Total	**1080**	**2298**	**2563**	**4004**
ORISSA				
Power	95	1597	3843	6898
Iron & Steel	136	153	170	187
Fertiliser	136	136	136	136
Cement	112	122	133	145
Domestic	81	118	168	247
Total	**560**	**2126**	**4450**	**7613**
ANDHRA PRADESH				
Power	846	3441	7970	15776
Iron & Steel	14	19	23	30
Fertiliser	650	1057	1057	1057
Cement	853	931	1017	1107
Domestic	613	1036	1340	1408
Total	**2976**	**6484**	**11407**	**19378**
TAMIL NADU				
Power	3044	9239	20364	29515
Iron & Steel	0	0	0	0
Fertiliser	734	734	734	734
Cement	513	562	611	668
Domestic	755	879	994	1157
Total	**5046**	**11414**	**22703**	**32074**
GRAND TOTAL	***9662***	***22322***	***41123***	***63069***

1.6.2. Industrial sector

The iron & steel industry consumes some amount of fuel oil which can be replaced by natural gas without much difficulty. Of the total consumption of fuel oil in the three steel producing states, iron & steel industries have a share of 7%, 22% and 3% in West Bengal, Orissa and Andhra Pradesh respectively. Assuming the same

shares to continue in the future, and using a natural gas equivalent of 1.19 MCM for every thousand tons of fuel oil, the natural gas sales potential in the iron & steel industry is calculated. A value of 913 Nm^3 of natural gas for every ton of ammonia has been used in the fertiliser industry, while in the cement and refractory industries, the equivalence factor is 410 MCM of natural gas for every ton of coal.

1.6.3. Domestic sector

The calculations for potential demand in the domestic sector are based on an equivalence factor of 1.233 cubic metre of natural gas for every kilogram of LPG.

1.7. IMPUTED VALUES FOR NATURAL GAS

1.7.1. Power sector

Imputed values for gas have been calculated for domestic and imported fuels, i.e. coal, naphtha and fuel oil. For coal, both conventional and integrated gassification coal combustion (IGCC) power stations have been considered. In commenting on the attractiveness of natural gas it has been assumed that it can be made available at average burner-tip prices of around $ 3.00/MMBtu in the study region. A lower price would of course give gas a greater competitive edge.

The following broad trends emerge:

1. **Gas vs. domestic coal (conventional plant)**: Costs of electricity generation based on domestic coal are around 4.30 cents/kWh. The imputed values for gas work out to about $ 3.50/MMBtu, which implies that gas can offer stiff competition to domestic coal.
2. **Gas vs. imported coal (conventional plant)**: Imputed values for gas work out to around $ 6.25/MMBtu, which are higher than the corresponding values for domestic coal. This is due to the fact that capital costs are assumed to be higher in the case of imported plants due to the FGD units, which are presently not mandatory in India as Indian coal has a low sulphur content, as also the higher price of imported coal relative to domestic coal.
3. **Gas vs. IGCC plants**: Imputed values for both indigenous and imported coal are higher than $ 7/MMBtu. This is primarily due to the very high capital cost of an IGCC plant.
4. **Gas vs. imported naphtha**: Imputed values for gas work out to be $ 4.70/MMBtu, implying that imported naphtha is not a competitor in the study region except at Madras and further south.
5. **Gas vs. domestic naphtha**: Imputed values for gas work out to between $ 5.25-5.67 /MMBtu.

6. **Gas vs. imported fuel oil**: Imputed values hover around the $ 3.75/MMBtu mark, despite the fact that imported fuel oil is heavily taxed (30% customs duty). If the customs duty were to be removed, the imputed value would come down to around $ 3.00-3.25/MMBtu level, implying that imported fuel oil could be a serious competitor to natural gas.
7. **Gas vs. domestic fuel oil**: The imputed values fall in the range of $ 5.46-5.92/MMBtu which implies that indigenous fuel oil poses no competitive advantages over natural gas.

Overall, the imputed value analysis shows that gas fired capacity has considerable potential and the economics is attractive vis-à-vis other fossil fuel options.

1.7.2. Industrial and domestic sectors

The imputed values worked out for the various industry types and the domestic sector are shown in Table 1.4.

Table 1.4: Imputed values of gas in industrial and domestic sectors

($/MMBtu)

Sector	Reference	Imputed value
Iron & steel	Fuel oil	4.35
Fertiliser	Naphtha	3.59
Fertiliser	Fuel oil	3.46
Cement	Coal	1.74
Domestic	LPG	4.60

CHAPTER 2
ENERGY SCENARIO IN INDIA

2.1. INTRODUCTION

For any developing country, the key concerns are economic growth, access to adequate commercial energy supplies, and the finances needed to achieve these objectives. Interest in India's energy sector has been growing with the continuing expansion of the Indian economy. In the fiscal year 1995-96, India's GDP grew at the rate of 7%, which surpassed earlier projections. An overview of the Indian economy reveals that over the last 5 years, the policy reforms of 1991 have led to a revival of strong economic growth, rapid expansion of productive employment, poverty reduction, a substantial boom in exports, and a significant decline in inflation.

There are also significant changes taking place within the energy sector in India. Some of these involve private sector participation in power generation wherein the earlier arrangement of coal linkages and tying up supply of fuels on a project-to-project basis is giving way to initiatives that provide power generators with flexibility in fuel supply options.

In the developing world, the first sign of improving standards of living is the increasing supply of energy. India's per capita consumption of energy is only 0.24 toe as against the world average of 1 toe and much higher levels in developed countries. The per capita consumption of energy in India is likely to rise, and though it may not come anywhere close to the consumption in developed countries, it will definitely see a steep increase in the next 15-20 year span, resulting in increased demand of energy.

As the Indian economy is poised for high growth in the coming years, it would not only be important to ensure that the supply of energy is adequate in physical terms, but also that it is obtained at the least possible cost to the country. Energy policies, and the organisations that implement them, now have to reorient their plans to ensure that the mix of energy sources to be used in the Indian economy is optimal and sustainable. Security of supply would be an important element of sustainability. In this respect, the role of hydrocarbons would not only continue to be important, but most likely increase in its relevance and in imparting dynamism to the Indian economy.

Given the rapid rate of growth in demand for energy, an assessment of the current situation and directions for change in the future is imperative at this juncture. There are several questions that arise which should guide the future policies and restructuring efforts in the immediate future. Some of these are related to international trends and developments and other arise out of India's own compulsions and preferences and are discussed below with reference to the various sectors.

2.2. POWER

India's power sector is dominated by different government agencies: ministries, authorities, regional and State Electricity Boards (SEBs) and generation and transmission companies. The performance of the industry has been below par and it has been characterised by several problems like high transmission and distribution (T&D) losses, poor financial health of the SEBs, low plant load factor, etc. In spite of having an installed capacity of about 94,000 MW (utilities and captive), India is plagued by energy and peak shortages which are estimated to be 9 and 18 percent respectively.

The generating capacity of utilities comprises a mix of hydro, coal/oil/gas based thermal and nuclear plants. The installed capacity of power utilities, which was about 1,700 MW in 1950-51, has grown to 83,000 MW by 1995-96. The annual rate of growth has been about 9.5% during this period. Up to mid 1960s, the thrust was more on developing hydro projects, but, since 1970s, the thermal capacity has shown remarkable increase and now stands at 72%. The share of hydro power rose to 43% in 1970-71, but has been steadily declining since then due to various reasons including increase in awareness among the populace about the environmental degradation and large scale displacement of persons, and is about 26% in 1995-96. The share of nuclear is almost stagnant at about 2.5%.

As the country's electricity-gross domestic product (GDP) elasticity is about 1.5, it is expected that with GDP growth of 6 to 8 percent per annum (p.a.), electricity demand would increase by 9 to 12 percent p.a. Such a growth in demand does not appear unrealistic given India's current low level of per capita electricity consumption, which at 314 kWh works out to be less than 4 percent of that of the Organisation for Economic Co-operation and Development (OECD) countries.

Despite high industrial growth in the last decade, the industrial sectors share in power consumption fell from 62% in 1980 to 38% in 1994. But the consumption of the agricultural sector grew from 12% in 1980 to 29% in 1994.

According to the Ministry of Power, to meet projected power demand, an incremental capacity addition of 142,000 MW is required over the fifteen year period starting 1992. This necessitates the setting up of incremental capacity of over 9,000 MW p.a. While capacity addition has been low in the recent past (averaging about 3,000 MW p.a. over 1992-1997), this can be expected to get an impetus as the policy framework to attract private power evolves. While a large domestic market and high private sector interest would tend to ensure that additions to power generation capacity take place, from the country's perspective it is imperative to ensure that least cost options are exercised when setting up additional capacity.

Lured by assured returns on equity many Indian and foreign companies submitted proposals to the Ministry of Power. Till March 1995, 179 plans for generation of about 65000 MW were submitted. The negotiation based approach for awarding a project has been the prime reason for the good response and most of the projects have not materialised. The Ministry of power has now replaced the negotiation-based approach with the competitive bidding route, a system that is more transparent and expected to reduce capital and operating costs

Neither the central, nor the state government, have a clearly defined guideline for an optimal fuel-mix for the various states. However the Rajyadaksha committee appointed by the Government of India in the early eighties to advise the government regarding various aspects of power sector, recommended a ratio of 60:40 for thermal and hydro installed capacities.

Usually, neither the central, nor the state government, specify the type of fuel to be used by an Independent Power Producer (IPP). The IPP selects the fuel based solely on its own economic considerations, but approval for the fuel-linkage is to be obtained from the Central Government.

The Central government has also decided not to allow any new generating stations to be based on gas oil as the fuel. This, however, is not applicable to generators which are installed as a back-up against failure of grid supply. The units which are set up to run on a continuous basis for sale of power to the grid are allowed to install generating units of the reciprocating type, and use heavy fuel oils instead of gas oil.

In a recent policy guideline the government has decided to extend limited counter guarantee for a few more power projects, apart from the in-principle counter guarantee extended by the government to the eight fast track projects. It has also promised to further streamline the policies on private investment in power projects. Further the government has decided to accord high priority to the renovation and modernisation schemes for improving the efficiency of the existing power plants.

2.3. COAL

The major reserves of power grade coal in India, as estimated by the Geological Survey of India, lie in the coal-fields of central and eastern India. Though coal is also mined in the north-eastern region of India, it has a low ash content and high calorific value, but does not get used for power generation. The coal from the north-east is also high in sulphur content.

Although coal is available in plenty, there is a serious problem as regards its quality. It is estimated that India has mineable reserves of about 100 billion tonnes which can ensure coal supply for over 200 years at the current rate of production of approximately 267 million tonnes per annum. In view of the favourable geological configuration, it is possible for the coal industry to supply one of the cheapest fuels to the economy closely competing with the natural gas. It is expected that the consumption of coal could exceed 600 million tonnes by the year 2010. However, the increase in coal consumption could be constrained due to the environmental restrictions.

Table 2.1 lists the major coal-fields in India by state and also gives the nodal rail-head for each developed coal-field. A number of coal-fields contain significant reserves, but do not have a nodal rail-head listed as they are virgin fields, and no infrastructure facilities are available at present at these locations.

The industrial sector is by far the largest consumer of coal in India, with 99% of all the coal consumed in India going to this sector. In industry, the power sector is the single largest consumer of coal followed by iron & steel and cement industries. The consumption of coal in the domestic sector again is insignificant.

Table 2.1: Inventory of geological reserves of non-coking coal as on January 1, 1997

(Million tons)

State	Coal-field (nodal rail-head)	Proved	Indicated	Inferred	Total
West Bengal					
	Raniganj (Asansol)	9,614.87	6,667.99	3,783.66	20,066.52
	Birbhum	0.00	3,178.66	435.17	3,613.83
Bihar					
	Raniganj (Asansol)	1,120.93	472.77	90.10	1,683.80
	Jharia (Dhanbad)	6,102.74	1,850.26	0.00	7,953.00
	North Karanpura (Patratu)	5,536.20	3,263.39	1,860.90	10,660.49
	South Karanpura (Patratu)	2,542.18	1,466.81	1,212.44	5,221.43
	Rajmahal (Pirpainti)	2,077.97	7,911.47	1,350.46	11,339.90
	Auranga	8.78	2,178.59	433.23	2,620.60
Orissa					
	Ib River (Jharsuguda)	1,962.69	10,289.58	9,058.04	21,310.31
	Talcher (Talcher)	5,135.19	12,571.97	8,872.36	26,579.52
Uttar Pradesh					
	Singrauli (Singrauli)	574.80	487.00	0.00	1,061.80
Madhya Pradesh					
	Pench-Kanhan (Eklehra)	1,097.46	311.96	170.02	1,579.44
	Sohagpur (Anuppur)	951.02	612.41	36.82	1,600.25
	Singrauli (Singrauli)	3,014.35	1,215.46	3,905.95	8,135.76
	Hasdo-Arand (Bisrampur)	680.67	2,798.06	842.05	4,320.78
	Korba (Korba)	2,478.62	6,246.14	1,135.64	9,860.40
	Mand-Raigarh (Raigarh)	293.43	7,550.47	1,980.73	9,824.63
	Tatapani-Ramkola	0.00	1,027.76	175.49	1,203.25
Maharashtra					
	Wardha Valley (Chandrapur)	2,423.24	958.17	1,404.61	4,786.02
	Kamptec	909.67	254.09	239.03	1,402.79
Andhra Pradesh					
	Godavari Valley (Dornakal)	6,624.83	3,496.73	2,935.67	13,057.23
Assam					
	Makum (Makum)	218.65	9.85	32.19	260.69
Arunachal Pradesh					
	Namchik	31.23	11.04	47.96	90.23
Meghalaya					
	West Daranggiri	93.31	33.69	0	127.00
	Balphakram-Pendenguru	0	0	107.03	107.03
	Slju	0	0	125.00	125.00
Nagaland					
	Borian	3.43	1.35	5.22	10.00

Source: Geological Survey of India, Ministry of Mines, Government of India

To ensure sustained and planned development of all facets of the coal industry, massive investment to the tune of about Rs 180 billion has been made, since nationalisation, in opening up of new mines, re-organisation of existing mines and development of associated infrastructure. Coal production has registered an annual growth rate of about 4.3% since nationalisation, increasing from a level of 73 million ton in 1970-71 to 270 million ton in 1995-96. In the post-nationalisation period, major thrust was given towards development of new outlying coalfields like Rajmahal, North Karanpura, Singrauli, Korba, Ib valley and Talcher. These coalfields contributed 43% of the total coal production in 1994-95.

The Government adopted a deliberate policy to increase production through opencast mines to meet the increasing demand of coal for the utilities. The opencast mines which contributed only about 28% of the total production at the time of nationalisation (1973), increased their share to about 72% in 1995-96. The major factors in favour of opencast mines are shorter gestation period, high recovery and safety, and lower cost of production. However bulk of coal produced from opencast mines is inferior grade coal. As a result of this policy, the production of inferior grades of both coking and non-coking coal have been increasing in the last two decades and this trend is continuing.

In 1970-71, 76% of total coal produced was non coking and the rest was coking. The production of the non-coking coal over the years has increased sharply, mainly due to the increasing demand of coal for power sector and it now stands at 84%. The percentage of coking coal production in total production has declined to 16% during the same period.

In the non-coking coal production, the share of superior quality coal (Grades A, B C & D) in 1970-71 was about 80%, which has declined in 1995-96 to about 50%. The balance 50% was inferior grade non-coking coal (Grade E, F & G). This declining trend in the production of superior grades is likely to continue in the future.

2.4. HYDROCARBONS

Bulk of the exploitable reserves of hydrocarbons are found in the states of western and north-eastern India. Crude oil is mainly found in the fields in Assam and Bombay High, with additional reserves in Nagaland, Andhra Pradesh and Tamil Nadu.

Natural gas, in addition to the states mentioned above, is also found in Arunachal Pradesh, Tripura, Gujarat, Rajasthan, and Andaman & Nicobar. Table 2.2 shows the distribution of the proven and balance recoverable reserves of crude oil and natural gas as estimated by the Government of India.

Table 2.2. Proven and balance recoverable reserves of crude oil and natural gas, 1995

Product	Location	Quantity	Remarks
Crude oil			
	Gujarat (on-shore)	154.6 MMT	
	Assam (on-shore)	155.1 MMT	Includes crude oil reserves in Nagaland and onshore reserves in Andhra Pradesh and Tamil Nadu
	Bombay High (off-shore)	416.8 MMT	Includes offshore reserves in Andhra Pradesh and Tamil Nadu
	Total	**726.5 MMT**	
Natural gas			
	Gujarat (on-shore)	89.9 BCM	
	Assam (on-shore)	161.9 BCM	Includes natural gas reserves in Tripura, Nagaland, Tamil Nadu, Arunachal Pradesh and Andhra Pradesh
	Rajasthan (on-shore)	1.4 BCM	
	Bombay High (off-shore)	389.6 BCM	Includes natural gas reserves in Andhra Pradesh, Gujarat, Tamil Nadu and Andaman
	Total	**642.8 BCM**	

Source: Indian Petroleum and Natural Gas Statistics, Ministry of Petroleum and Natural Gas, GOI

The demand for hydrocarbons compared with primary source, i.e. coal in India, is expected to grow vigorously in the coming decades resulting from economic growth, population changes, increase in disposable household incomes, and changes in the capital intensity of the Indian economy and as environmental factors and the cost of rehabilitation of land in coal mining areas add significantly to the cost of coal mining. In addition, given the fact that coal reserves are predominantly located in the eastern and south-eastern parts of the country, transportation costs, particularly where new transport capacity additions are involved, would make the price of coal at consumption points in other parts of the country much higher than current levels particularly favouring greater use of natural gas (whether indigenously produced or imported). Yet the infrastructure for natural gas transportation and distribution is confined to serving only a small part of the country. If growth in this subsector is to take place in keeping with future demand scenarios, structuring a dynamic industry for natural gas supply and distribution becomes imperative. Hence in view of the fact that in the near future the country would be deficient in liquid hydrocarbon

production, and that liquid hydrocarbons have the unavoidable pollution hazards, stronger focus is now necessary to tie up for long term gas imports through pipeline and/or liquefied natural gas (LNG) in the future.

2.5. CONCLUSION

India's energy sector is going through a period of reform, and in the recent past, there has been an increasing trend towards collaboration with private sector: both national as well as international. The essence of restructuring the hydrocarbon industry is to introduce and foster the conditions of a competitive market so as to stimulate improvements in productivity and maximise the consumer surplus. The power sector has been opened for private participation in the area of generation and there is a increasing trend towards tariff and State Electricity Board reforms. Further reforms in transmission, distribution and modernisation of old plants are imperative for the success of the private power initiative program, and are expected to come through in the near future. The success of the reforms program in the energy sector would largely depend on the political will of the government, efficient management of the transition period and pursuance of a transparent policy.

CHAPTER 3
ENERGY POLICIES, PRICING AND REGULATORY MATTERS

3.1. STRUCTURE AND POLICIES

3.1.1. Electricity

The Constitution of India defines the powers of the Central Government, State Governments and Local Bodies in urban and rural areas. The Seventh Schedule of the Indian Constitution defines the independent powers of the Union and State Governments in the Union and State Lists. It also outlines the areas of shared responsibility between the two, in the Concurrent List. For subjects in the Concurrent List, both the Union and the State Government have the powers to legislate, though the Union legislation will always have precedence over the State legislation.

Electricity is mentioned in entry number 38 under List 3, which is the Concurrent List of the Seventh Schedule. This means that electricity comes under the purview of both the Central and State governments and the powers to regulate through legislation and to tax remain with both the Union and the State Governments.

It was after independence that the Government of India formalised the responsibility of the public sector in power development by enacting the Electricity (Supply) Act in 1948. Under Section 3 of this Act, the Central Electricity Authority (CEA) was constituted and charged with the responsibility of developing a sound, adequate and uniform national policy in relation to the control and utilisation of national power resources. The CEA, inter alia, conducts the techno-economic appraisal of the project reports in respect of setting up of generating stations in the country and issues techno-economic clearances for projects. Under section 5 of this act, the State Electricity Boards (SEBs) were created as statutory organisations responsible for the efficient and economic development of the power sector in their respective states.

At the central level, within government, power as a subject is dealt by the Ministry of Power (MOP). The organisation chart of the MOP is provided in Appendix 3.1. Figure 3.1 shows the various power sector organisations.

Active Central participation in the expansion of power generation programme started with the creation of two public sector generation companies; National Thermal Power Corporation (NTPC) and National Hydro Power Corporation (NHPC) during

the year 1975. These corporations were created for two main reasons. The first is that it is easier for the Central Government Undertakings to execute and operate generating stations which benefit more than one state. The other is that the SEBs and the state governments did not have the requisite funds to finance the construction of new power stations. The Power Grid Corporation of India Ltd. (PGCIL) was established in 1989 to develop and manage a national grid by integrating the five regional grids. The main objective is to facilitate transfer of power within and across regions with reliability, security and economy, on commercial principles. Two specialised public financial institutions for financing power development have also been created by the Central Government. The Rural Electrification Corporation (REC) was established in 1969 mainly to finance extension of the distribution network in rural areas. The Power Finance Corporation (PFC) was established in 1986 to channelise foreign multilateral, bilateral and commercial debt and domestic debt for the development of the state level power sector.

The regulatory structure underwent significant changes in 1991 to facilitate the entry of private capital and management in power development. As per Amending Act 50 of October 15, 1991 a generating company can now be formed either in the public sector, or in the private sector or in the joint sector. Prior to this amendment private sector involvement was limited to the role of a licensee. Licensees were primarily bulk or retail suppliers of electric power though they were also permitted to generate power for self distribution. The amending act of 1991 also increased the powers of the State Governments by making them the 'competent government' for all generators, within their jurisdiction, including private generators, except generating stations owned by the central government.

At the state level, in the states of Andhra Pradesh, Tamil Nadu and West Bengal, while the SEBs are responsible for setting the electricity tariffs applicable to the different sectors, it is the state government which is the final approving authority on the tariffs. Due to this, more often than not, the tariffs for domestic and agriculture consumers are set based on political considerations rather than economic.

The model is somewhat different in case of Orissa. The electricity industry in the state is in the process of restructuring and privatisation, and the Orissa State Electricity Board has been dissolved. The Electricity Reform Bill, 1995, was passed by the Orissa legislative assembly on November 28, 1995 to provide for the restructuring of the electricity industry. This bill provides avenues for participation of

private sector entrepreneurs in the power sector and generally for taking measures conducive to the development and management of the power sector in an efficient, economic and competitive manner.

According to this bill, the erstwhile Orissa State Electricity Board (OSEB) has been split into a generating corporation and a transmission company. The bill has also provided for the constitution of an electricity regulatory commission for the State named as Orissa Electricity Regulatory Commission (OERC). This commission consists of three members appointed by the State government. The primary functions of the commission are to aid and advice, in matters concerning generation, transmission and distribution of electricity in the State. The other important function is to issue licences to various generating/transmitting and distributing companies in accordance with the provisions of this act and to regulate the working of licensees in an efficient, economical and equitable manner. OERC also regulates the purchase, distribution, supply and utilisation of electricity, the quality of service, the tariff and charges payable keeping in view both the interest of the consumer as well as the suppliers.

In this liberalised power sector scenario in Orissa, the state government has the powers to issue policy directives on matters concerning electricity. The state government is entitled to issue directives concerning subsidies to be allowed for supply of electricity to any consumer category provided the state government pays the amount to compensate the concerned authority to the extent the subsidies are granted.

The state governments in consultation with the respective SEBs, are also authorised to clear power generation projects which involve a capital expenditure of less than Rs 10 billion (approximately US $ 286 million), provided the project is competitively bid. This translates to projects of approximately 250 MW capacity, taking the average capital cost to be Rs 40 million (approximately US $ 1.14 million) per megawatt. Any project which exceeds this limit, has to obtain clearances from the Central Electricity Authority.

A conscious decision has been taken by the Government of India to increasingly rely on Independent Power Producers (IPPs) for addition of new generating capacities. Towards this end, entry of private generators was allowed through an amendment to the E(S)A, 1948 in October 1991. 100% foreign owned companies are now

permitted to set up power projects and repatriate profits without any export obligations, and a five year tax holiday has been granted to IPPs.

The SEBs are at present the only customers of power generated by the IPPs. The tariff at which power is purchased by a SEB from an IPP is decided through the competitive bidding process and/or negotiations between the IPP, SEB, and the state government. A notification has been issued in March 1992 by the Government of India for a two-part tariff structure, permitting full recovery of fixed charges with up to 16% return on equity at 68.5% plant load factor, and also full recovery of the variable (fuel) charges.

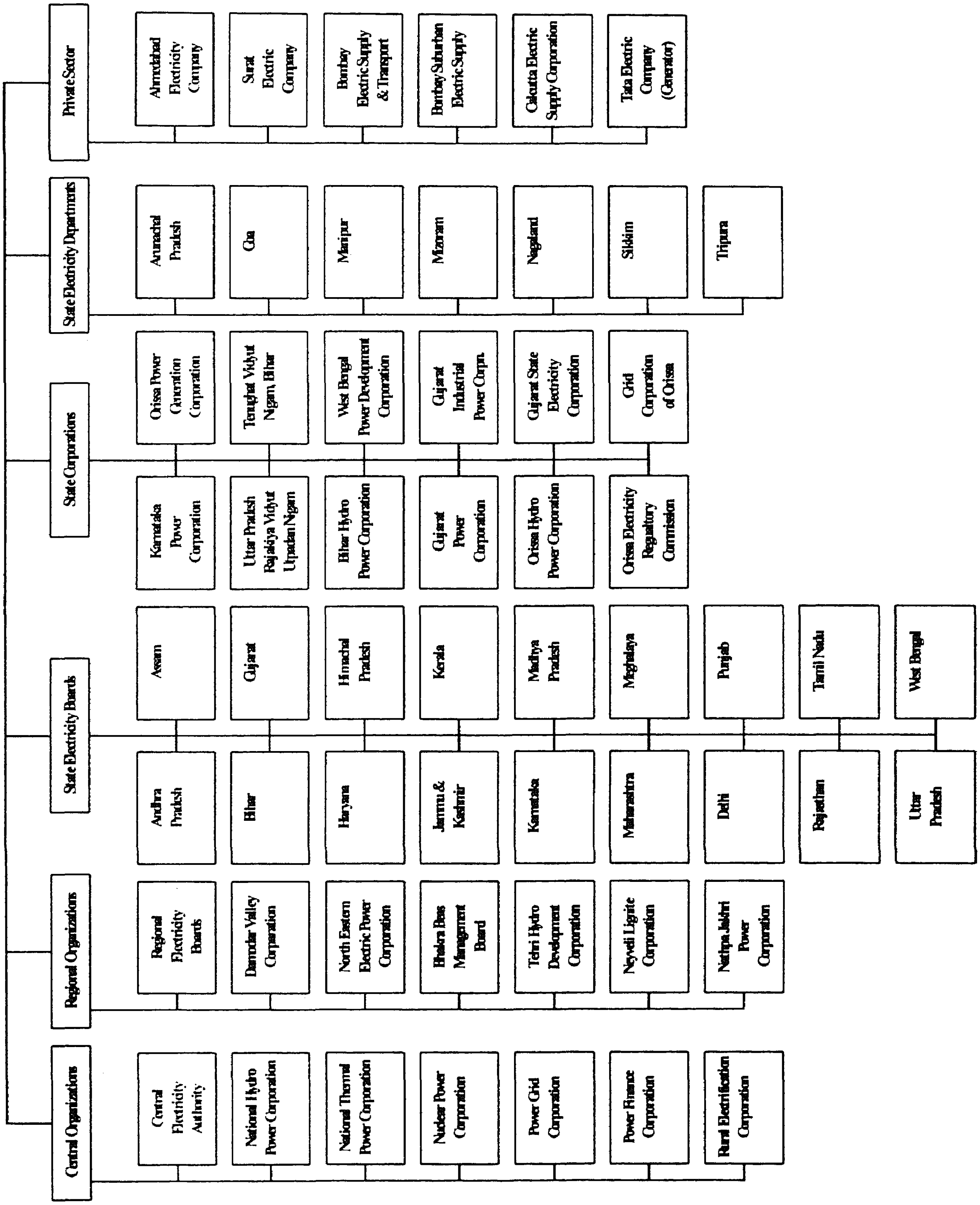
While the state governments are authorised to clear projects of up to 250 MW capacity, the fuel linkages have to be approved by the relevant ministries in the central government. Coal is handled by the Ministry of Coal, hydrocarbons by Ministry of Petroleum and Natural Gas, and water for hydro schemes by the Ministry of Water Resources. The Ministry of Environment and Forests at the centre is the final authority on environmental clearances.

Therefore, while the state governments have some autonomy in the approval process for power stations of up to 250 MW capacity, the central government still has the final say on the approval of a project.

Also important to note is that all proposals for foreign investment in power, or in any other industry for that matter, whether through setting up of a new company or through the purchase of equity in an existing company, need to be approved by the Foreign Investment Promotion Board (FIPB) now under the Ministry of Industry but formerly under the Prime Minister's Office.

The Government of India had also issued an ordinance in the beginning of 1997 which allowed the participation of the private sector in power transmission. Unfortunately, due to the government's failure in getting the Electricity Act Amendment Bill passed by Parliament, the ordinance has lapsed and may affect the upcoming private sector generating units as the infrastructure will be lacking to evacuate the power generated by them.

Figure 3.1: Power sector organisations


Private Sector
Ahmedabad Electricity Company
Surat Electric Company
Bombay Electric Supply & Transport
Bombay Suburban Electric Supply
Calcutta Electric Supply Corporation
Tata Electric Company (Generator)
State Electricity Departments
Arunachal Pradesh
Goa
Manipur
Mizoram
Nagaland
Sikkim
Tripura
State Corporations
Orissa Power Generation Corporation
Tenughat Vidyut Nigam, Bihar
West Bengal Power Development Corporation
Gujarat Industrial Power Corpn.
Gujarat State Electricity Corporation
Grid Corporation of Orissa
Karnataka Power Corporation
Uttar Pradesh Rajakiya Vidyut Utpadan Nigam
Bihar Hydro Power Corporation
Gujarat Power Corporation
Orissa Hydro Power Corporation
Orissa Electricity Regulatory Commission
State Electricity Boards
Assam
Gujarat
Himachal Pradesh
Kerala
Madhya Pradesh
Meghalaya
Punjab
Tamil Nadu
West Bengal
Andhra Pradesh
Bihar
Haryana
Jammu & Kashmir
Karnataka
Maharashtra
Delhi
Rajasthan
Uttar Pradesh
Regional Organizations
Regional Electricity Boards
Damodar Valley Corporation
North Eastern Electric Power Corporation
Bhakra Beas Management Board
Tehri Hydro Development Corporation
Neyveli Lignite Corporation
Nathpa Jakhri Power Corporation
Central Organizations
Central Electricity Authority
National Hydro Power Corporation
National Thermal Power Corporation
Nuclear Power Corporation
Power Grid Corporation
Power Finance Corporation
Rural Electrification Corporation

3.1.2. Coal

The Ministry of Coal is responsible for development and exploitation of coal and lignite reserves in India. The subjects allocated to the Ministry under the Government of India (Allocation of Business) Rules, 1961, as amended from time to time, are as follows:

(i) Exploitation and development of coking coal and non-coking coal and lignite deposits in India.

(ii) All matters relating to production, supply, distribution and pricing of coal.

(iii) Development and operation of coal washeries.

(iv) Administration of Coal Mines (Conservation and Development) Act, 1974 (28 of 1974).

(v) Administration of the Coal Mines Provident Fund and Miscellaneous Provisions Act, 1948 (46 of 1948) and all matters relating to the Coal Mines Provident Fund Organisation.

(vi) Administration of residual matters relating to the Coal Mines Labour Welfare Organisation since abolished with effect from 1.10.1986.

(vii) Administration of the rules under the Mine Act, 1952 (32 of 1952) for levy and collection of excise duty on coke and coal produced and despatched from mines.

(viii) Administration of Coal Bearing Areas (Acquisition and Development) Act, 1957 (20 of 1957).

(ix) Administration of Public Sector Enterprises dealing with coal and lignite.

(x) Administration of Mines and Minerals (Regulation and Development) Act, 1957 (67 of 1957) and other Union Laws in so far as the said Act and other Laws relating to Coal and Lignite and use of sand for stowing purposes.

(xi) All business incidental to the administration of above activities including matter concerning the state governments.

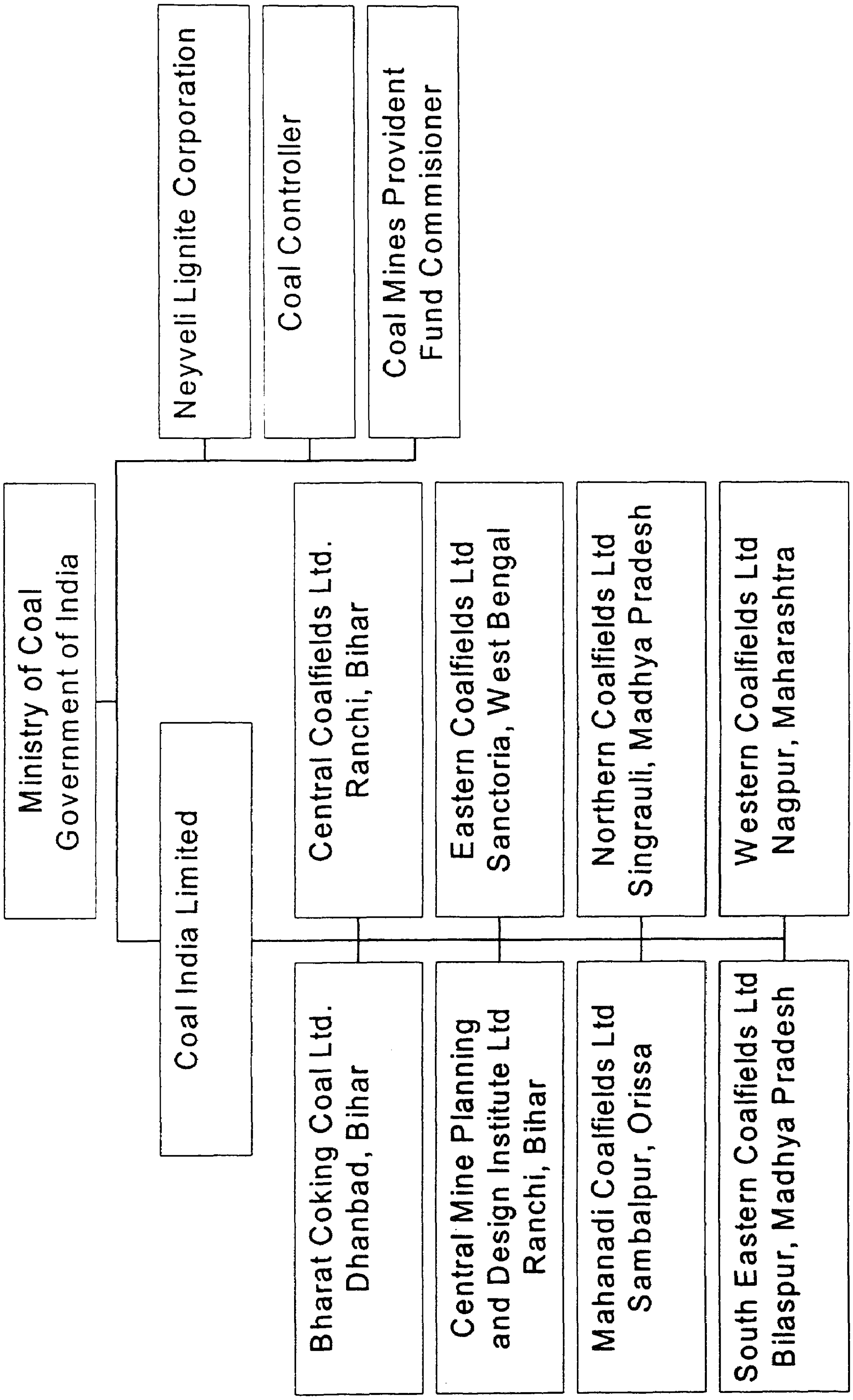
The Ministry has under its administrative control the Coal India Limited (CIL), a Public Sector Undertaking, along with its eight subsidiary companies (see Figure 3.2). CIL with its headquarters at Calcutta in West Bengal is the holding company in respect of these subsidiaries. It is also the apex body in the coal industry and is responsible for laying down the policy guidelines and co-ordination work of subsidiaries. It also does the investment, planning, manpower, management, purchase of heavy machinery, financial budgeting etc. on behalf of all its subsidiaries. While seven of the subsidiaries of the Coal India Limited are producing companies directly engaged in raising and distribution of coal, the Central Mine Planning and Design Institute Limited is the planning, designing and engineering company whose function is to render expert service on mineral exploration, planning and designing of coal projects, coal beneficiation, coal utilisation, environmental management, etc. and to transfer foreign technology for assimilation in Indian conditions.

The Ministry of Coal also has under its administrative control the Neyveli Lignite Corporation with headquarters at Neyveli in Tamil Nadu. The company is engaged in exploitation of lignite deposits and generation of lignite-based power in Tamil Nadu.

The Government of India and the state government of Andhra Pradesh have also formed a joint-venture company, Singareni Collieries Company Limited (SCCL). The equity capital is shared in the ratio of 51:49 between the state and central governments respectively. This company operates coal mines located in the state of Andhra Pradesh.

The Ministry of Coal has two other organisations under its administrative control, namely the Coal Controller's Organisation, and the Coal Mines Provident Fund Organisation.

Figure: 3.2: Coal industry organisations

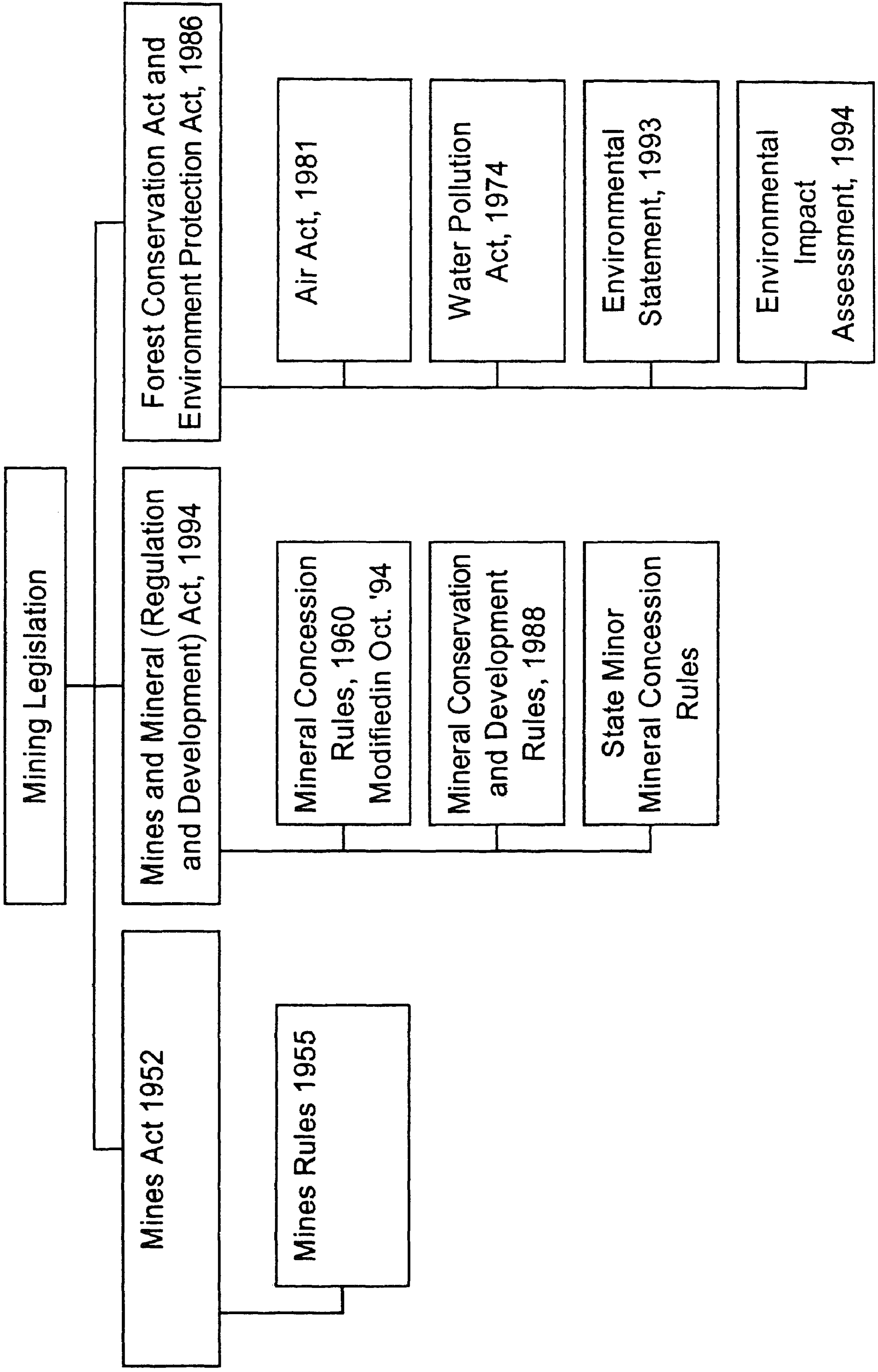

Ministry of Coal
Government of India
Neyveli Lignite Corporation
Coal Controller
Coal Mines Provident Fund Commisioner
Coal India Limited
Central Coalfields Ltd. Ranchi, Bihar
Eastern Coalfields Ltd Sanctoria, West Bengal
Northern Coalfields Ltd Singrauli, Madhya Pradesh
Western Coalfields Ltd Nagpur, Maharashtra
Bharat Coking Coal Ltd. Dhanbad, Bihar
Central Mine Planning and Design Institute Ltd Ranchi, Bihar
Mahanadi Coalfields Ltd Sambalpur, Orissa
South Eastern Coalfields Ltd Bilaspur, Madhya Pradesh

The Coal Controller's Organisation is a subordinate office of the Ministry of Coal, having its headquarters at Calcutta and two field offices at Dhanbad and Asansol. The Coal Controller has certain statutory functions to perform. His statutory authority is derived from the following statutes:

1. Colliery Control Order, 1945, which authorises the Coal Controller to:
    a) monitor the quality of coal and settle the complaints against grading and sub-standard despatches of coal;
    b) grant permission and opening and reopening of seams and mines; and
    c) undertake distribution of coking coal.
2. Coal Mines (Conservation and Development) Act, 1974 and Rules made thereunder, which authorise the Coal Controller to:
    a) make recommendations for payment of subsidy towards stowing and protective works for conservation purposes;
    b) assess and collect stowing excise duty;
    c) function as Secretariat of the Coal Conservation and Development Advisory Committee; and
    d) monitor coal shipment to power houses and cement plants.
3. Statistics Act 1953, which authorises the Coal Controller to:
    a) collect statistical information regarding production and value of coal, distribution etc. and to public documents; and
    b) Coal Bearing Areas (Acquisition and Development) Act 1957 & Rules made thereunder.
        - Under this act, coal controller functions as a "Hearing Authority" for disposal of objections under section 8 of the above act against acquisition of coal bearing land by the coal companies

The Acts and Rules which govern coal mining activities are shown in Figure 3.3.

Figure 3.3: Mining legislative framework


Mining Legislation
Mines Act 1952
Mines Rules 1955
Mines and Mineral (Regulation and Development) Act, 1994
Mineral Concession Rules, 1960 Modifiedin Oct. '94
Mineral Conservation and Development Rules, 1988
State Minor Mineral Concession Rules
Forest Conservation Act and Environment Protection Act, 1986
Air Act, 1981
Water Pollution Act, 1974
Environmental Statement, 1993
Environmental Impact Assessment, 1994

3.1.3. Hydrocarbons

The Ministry of Petroleum and Natural Gas under the Government of India is responsible for the exploration and exploitation of petroleum resources, including natural gas. Its role extends to the production, refining, supply, distribution, marketing and pricing of petroleum products and natural gas. Exports and imports of crude oil, petroleum products and gas are also under its control.

While the production and exploration for oil and natural gas is carried out by the Oil and Natural Gas Commission (ONGC) and Oil India Limited (OIL), the Gas Authority of India Limited (GAIL) is concerned with all post exploration activities concerned with Natural Gas. ONGC was formed in 1956 and carries out exploration, development and production for the majority of oil fields, both on-shore and off-shore, in India. Oil India Private Limited was incorporated in 1959 as a joint venture of Burmah Oil Company/Assam Oil Company and Government of India. Eventually Oil India Limited became a Government of India Enterprise in the year 1981. The primary responsibilities of OIL are exploration, development, production and transportation of oil and gas mainly in the North-eastern part of India with additional operations in Rajasthan and Orissa. GAIL was formed in 1984 to take charge of processing, transportation, fractionating and marketing of gas. It operates a network of over 3,600 kilometres of gas pipelines spread all over the country. It has also been entrusted with the responsibility for setting up the infrastructure for use of Compressed Natural Gas (CNG) in the transport sector in the cities of Bombay, Delhi, and Baroda.

The Burmah Shell refinery was incorporated as the Bharat Petroleum Corporation Limited (BPCL) and the ESSO and the Caltex refineries were incorporated as Hindustan Petroleum Corporation Limited (HPCL). In pursuance of Industrial Policy resolution, the Government of India decided to move towards greater self sufficiency, forming two public sector companies in 1958 - the Indian Refineries Limited for production, and the Indian Oil Company for marketing, which were later merged in 1964 to form the Indian Oil Corporation (IOC).

The other important organisations under the Ministry of Petroleum and Natural Gas are:

1. **Oil Coordination Committee (OCC):** OCC was set up in 1975 and its main functions encompass co-ordinating various activities such as planning for imports and exports of crude oil and products. OCC prepares short term estimates of

supply & demand, operates and maintains pool accounts and monitors the performance of the industry with a view to achieve optimum utilisation of the refining capacity.

2. **Oil Industry Development Board (OIDB):** OIDB was set up in 1975 to provide financial assistance for the development of the oil industry. The financial assistance is extended by way of loans and grants for activities related to production, refining, and marketing oil products. The funds for the OIDB are made available by the Central Government from the proceeds of a cess that is levied on the production of indigenous crude oil.
3. **Directorate General of Hydrocarbons (DGH):** Formed in 1993, the DGH functions as a regulatory arm of Ministry to:
   a) provide technical advice to the Ministry on Exploration and Production (E&P);
   b) review the exploration programs of the E & P companies; and
   c) advice the Government on the future exploration strategies.

The tasks of the Ministry are exercised through various other public sector undertakings (PSUs), their subsidiaries and other organisations also, shown in Figures 3.4 and 3.5.

Figure 3.4: PSUs under the Ministry of Petroleum and Natural Gas

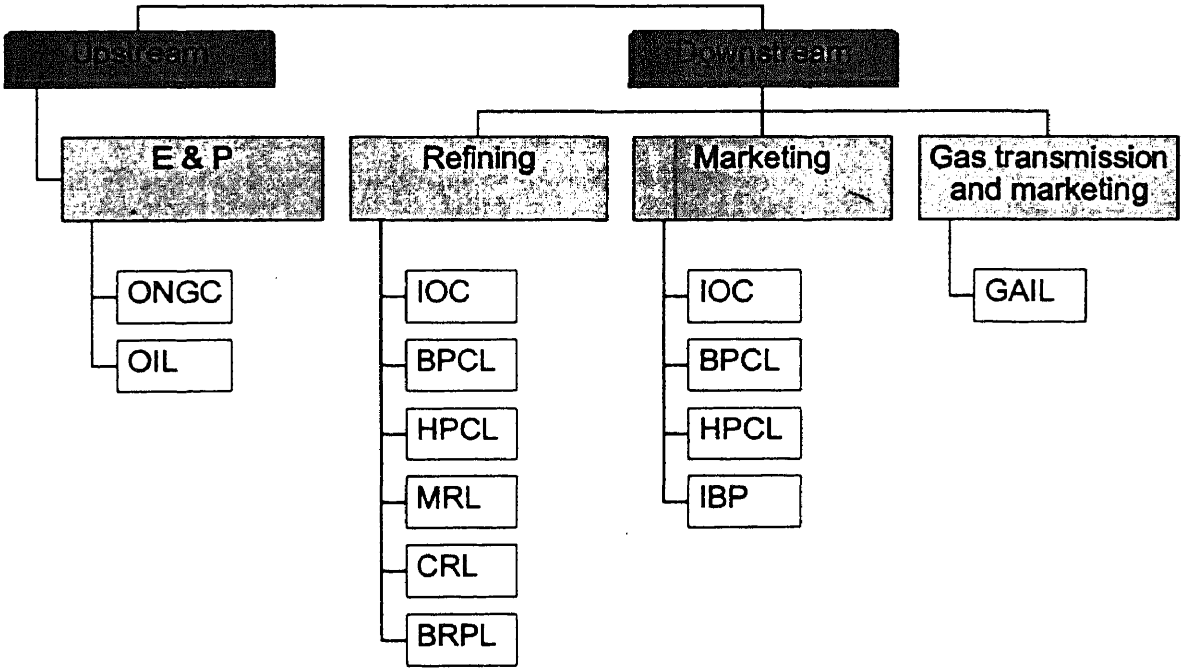
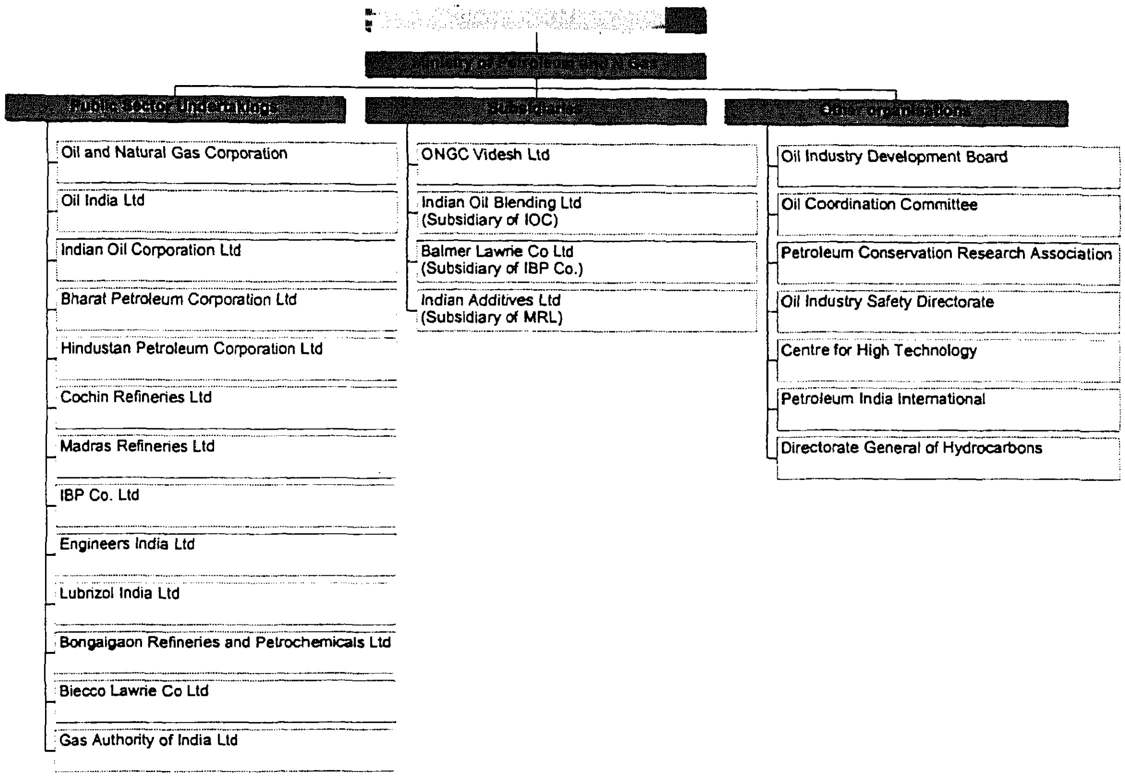


Figure 3.5: Organisation of the Indian hydrocarbon sector


Ministry of Petroleum and Natural Gas
Public Sector Undertakings
Subsidiaries
Other organisations
Oil and Natural Gas Corporation
Oil India Ltd
Indian Oil Corporation Ltd
Bharat Petroleum Corporation Ltd
Hindustan Petroleum Corporation Ltd
Cochin Refineries Ltd
Madras Refineries Ltd
IBP Co. Ltd
Engineers India Ltd
Lubrizol India Ltd
Bongaigaon Refineries and Petrochemicals Ltd
Biecco Lawrie Co Ltd
Gas Authority of India Ltd
ONGC Videsh Ltd
Indian Oil Blending Ltd (Subsidiary of IOC)
Balmer Lawrie Co Ltd (Subsidiary of IBP Co.)
Indian Additives Ltd (Subsidiary of MRL)
Oil Industry Development Board
Oil Coordination Committee
Petroleum Conservation Research Association
Oil Industry Safety Directorate
Centre for High Technology
Petroleum India International
Directorate General of Hydrocarbons

3.1.3.1. Legislative and regulatory framework

In 1948, the Government of India announced an Industrial Policy Resolution, under which the demarcation of industrial activity between the public sector and private enterprises was announced. In the case of mineral oil the existing units were to remain in the private sector but the government had the exclusive right to start all new units.

The legislations applicable to exploration and production of hydrocarbon resources are given below:

The Oilfields (Regulation and Development) Act 1948

This Act empowers the Union Government to regulate the award of rights for the exploration and production of mineral oil and natural gas in India. The Petroleum and Natural Gas Rules, 1956 framed under sections 5 & 6 of this Act, allow two types of rights to be awarded: the Petroleum Exploration Licence, and the Mining Lease. The rules relating to the award of mining rights are the same for onshore as for offshore, except that in the latter case, the licences are awarded exclusively by the Central Government, while in the former case they are awarded by the respective State Governments with the approval of the Central Government. The

Petroleum Exploration Licence provides the exclusive right to carry out a range of exploratory activities in the licensed area over a specified period. In the event of a discovery this licence is converted into a Mining Lease. This grants exclusive rights to exploit hydrocarbons subject to subject to limitation on mining areas, validity and payments as prescribed by the Act.

Territorial waters, continental shelf, exclusive economic zone and other maritime zones Act 1976

The legal regime governing offshore areas of India is based on Article 297 of the Indian Constitution and the Maritime Zones Act 1976. All rights over economic activity in the shelf are vested in the Union and the coastal federating states have no rights over shelf resources. More specifically in the context of hydrocarbon exploration and production activity, these rights include exploration, exploitation, offshore terminals, installations and other structures and devices necessary for exploration and resources.

Further all exploration and production activities in the hydrocarbon sector have to confirm with the Income Tax Act 1961 and the Foreign Exchange Regulations Act (FERA) and the Environment Protection Act (EPA) 1986.

In 1956, the Government announced a new Industrial Policy Resolution under which the mineral oil was to be the exclusive monopoly of the state. The Industrial Policy Statement, 1991 took note of the problems manifesting the public sector and initiated a process of gradual privatisation and the reform of the industry.

3.2. PRICING STRUCTURE, TAXES AND DUTIES

3.2.1. Electricity

3.2.1.1. Overview of tariff regulation

Guidelines for the determination of power tariffs exist only in a broad sense in the Electricity (Supply) Act 1948 which enjoins the SEBs to carry on their operations, as far as practical, without incurring losses. Hence the only statutory guideline for the fixation of tariffs is only by indicating a minimum rate of return (ROR) which the State Electricity Boards (SEBs) must earn on their investments. Prior to 1978 the E(S) Act envisaged only recovery of cost by the SEBs and did not mention the generation of a surplus by the SEBs. Hence at that time all capacity expansion was expected to be financed by government grant. With public expenditure increasingly coming under pressure the financial performance and pricing policies of the power sector has been the subject of enquiry by several government committees. A Working Group set up by the Planning commission in 1963 on pricing policy of the SEBs had

recommended that the Boards should earn a ROR of 12% (including electricity duty[1]) on capital investments after providing for expenses and depreciation. Subsequently the Venkataraman Committee in 1964, recommended a rate of return of 11% on the capital employed and suggested that this ROR should be achieved in a phased manner within next 10 years. This return was to be computed after providing for operating costs and depreciation. The net return on capital employed worked out to be 3%, after providing for interest charges (6%), transfer to general reserves funds (0.5%) and electricity duty (1.5%).

The E(S) Act was amended in 1978 to make SEBs commercially viable and earn a net rate of return on their investments. However no specific minimum ROR was specified. SEBs were required to adjust tariffs to ensure the generation of such surplus as specified by the state governments from time to time. The Rajadhyaksha Committee in 1980, taking into account the increase in the general level of interest rates recommended a minimum ROR of 15% on the average capital employed. Vide an amendment in 1983 it was specified that the SEBs should earn a minimum net return of 3% on the net fixed assets as at the beginning of the financial year and this guideline continues today. State governments are authorised to specify ROR higher than the minimum level also but in practice however most of the SEBs have failed to earn even the minimum stipulated return. State governments have not revised tariffs in line with rising cost and have indiscriminately subsidised the agricultural and domestic consumers.

3.2.1.2. Tariff fixation for retail or bulk sale to consumers by SEBs

Section 49 of the Electricity (Supply) Act, 1948 governs the sale of electricity to the consumers by the SEBs. This section gives only the broad principles of fairness and avoidance of undue preference to be followed by the SEBs in tariff fixation within a single consumer class. This section clearly gives SEBs the right to price discriminate across consumer classes and geographical boundaries keeping in mind the nature of power supply as well as the purpose for which the supply is required.

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[1] Electricity Duty is collected by the SEBs on behalf of the state governments from consumers at rates specified by the state governments. The SEBs act as agents for the collection of this duty which is subsequently deposited by them with the state governments. No service charge is currently paid to the SEBs for this service.

3.2.1.3. Tariff fixation for retail or bulk sale to consumers by licensees

Section 57 of the E(S) Act makes applicable Schedule 6 of the Act which specifies the procedure for the fixation and revision of tariff by a licensee. The broad principles are that revision is permitted, once every year, with the approval of the state government. The basis for calculation of the tariff remains as in the case of the SEBs assurance of a minimum return on capital employed though no minimum limit is prescribed under this schedule and it is left to the discretion of the state government.

3.2.1.4. Tariff fixation for bulk sale by public generators

Section 43A of the E(S) Act provides where the generator is wholly or partially owned by the central government, the terms and conditions of sale and the tariff will be decided by the central government. For generators, wholly or partly owned by states, the state government would decide the terms and conditions of sale and the tariff. However in determining the tariff the norms for operations and plant load factor would be used as prescribed by the Central Electricity Authority (CEA) and the rates for depreciation and reasonable ROR as determined by the central government.

3.2.1.5. Tariff fixation for bulk sale by private generators

In the case of private generators section 43A prescribes that they can either enter into a contract for the supply of power to the SEB or to any other individual with the approval of the concerned state government. The state government would keep the operational norms prescribed by the CEA like PLF and the depreciation rates and reasonable rates of return as prescribed by the central government.

3.2.1.6. Revision of Tariffs

Tariff revisions by the SEBs are generally carried out on an ad hoc basis. The sole criterion is the absorbing capacity of the consumers. The additional costs to be recovered are calculated first. Based on this, the extent to which rates for High Tension (HT) consumers can be raised is decided. The balance cost to be recovered is then adjusted to the extent possible from the Low Tension (LT) industrial, commercial and domestic consumers. The tariff for agricultural consumers is the most "sticky" due to political considerations. All the Boards have a fuel adjustment clause in their tariffs, which facilitates them to increase the energy charge for electricity whenever there is any increase in the cost of fuel, i.e., coal, oil. gas, etc. Boards generally pass on the increase in fuel cost to all categories except

domestic, agriculture and small industries. Revision is permitted once every year with the approval of the state government.

3.2.1.7. State Electricity Duty

The states are empowered to levy a State Electricity Duty (SED) on sales of electricity if they so wish. While Orissa, Tamil Nadu and West Bengal do not levy any SED on electricity, Andhra Pradesh levies a duty of 2.93 paise/kWh (as on March 31, 1997). This translates to about 2.05% of the state's average tariff.

Table 3.1: Average electricity tariff and average cost of supply for utilities (1995-96)

(paise/kWh)

State	Domestic	Commercial	Agriculture	Industrial	Average tariff	Cost of supply
West Bengal	70.30	158.00	26.90	183.50	154.88	187.90
Orissa	85.00	110.00	50.00	173.30	131.79	127.90
Andhra Pradesh	90.00	168.90	7.40	207.20	126.43	151.10
Tamil Nadu	92.10	237.50	0.00	227.50	146.33	178.00

($/MMBtu)

State	Domestic	Commercial	Agriculture	Industrial	Average tariff	Cost of supply
West Bengal	5.89	13.23	2.25	15.36	12.97	15.73
Orissa	7.12	9.21	4.19	14.51	11.03	10.71
Andhra Pradesh	7.53	14.14	0.62	17.35	10.58	12.65
Tamil Nadu	7.71	19.88	0.00	19.05	12.25	14.90

3.2.2. Coal

3.2.2.1. Pit-head price

The Central government administers the pit-head price of coal while leaving the price paid by the consumers largely unregulated. Thus, to arrive at the delivered market price, to the pit-head price of coal are added the loading/transport charges at the pit-head, processing charge, royalty, cess, duties and taxes, and the transportation and handling cost from the colliery to the consumer. The pit-head price of coal has been fixed as Rs 357.00 per ton for grade 'F' coal, the grade of coal used in thermal power stations. For the grade 'D' coal used in cement plants, the pit-head price is Rs 804.00 while it is Rs 1246.00 for coking coal.

3.2.2.2. *Transportation charges at pit-head*

Where coal is transported beyond a distance of 3 km to the loading point, the coal companies are entitled to charge additional transport costs from the purchasers at the following rates.

- Distance more than 3 km but not more than 10 km, Rs 21.00 per ton.
- Distance more than 10 km but not more than 20 km, Rs 40.00 per ton.

3.2.2.3. *Royalty*

The royalty on coal production is collected by the concerned state governments. The Central Government had last revised the rates of royalty on coal on 11.10.1994 and they are due for another revision at this time. The process of revision is going on currently, and the new rates are expected to be announced by the year end. The existing rates are given in Table 3.2.

Table 3.2: Existing rates of royalty on coal

(Rs/ton)

Coal group	Royalty w.e.f. 11.10.94
Group I (Coking SG I, II, WG I)	195
Group II (Coking Coal WG II, III, SC I, II, Non-Coking A, B)	135
Group III (Coking Coal WG IV, Non-Coking C)	95
Group IV (Non-Coking D, E)	70
Group V (Non-Coking F, G)	50
Group IV (Coal produced in Singareni, Andhra Pradesh)	75

3.2.2.4. *Duties and taxes*

Stowing excise duty: A uniform charge of Rs 3.50 per ton is levied on coal price as stowing excise duty.

Taxes: Central Sales Tax is levied on the price of coal at the pit-head at a uniform rate of 4% if the coal is transported outside the state where it is produced. If the coal is consumed in the same state where it is produced, State Sales Tax is applicable.

For non-coking coal (used in power stations), the import duty is 10% of the CIF value.

3.2.2.5. Transportation cost from colliery to consumer end

The freight rates charged by the railways for coal movement are used to cross-subsidise the movement of foodgrains and fertilisers. These freight rates are specified according to different distance slabs, varying from 100 to 5000 km. The rail tariff per tkm has been increasing regularly over the years, and the latest hike of about 12% over the previous rates was announced in February 1997.

The rail tariff per ton km for coal movement by railroad gradually decreases from Rs 0.92 per tkm for a haul of 100 km to Rs 0.69 per tkm for a haul of 600 km, in slabs of about 4 km for grade 'F' coal to be used for power generation. The average lead for coal movement in India by rail is about 700 km and the tariff is Rs 0.68/tkm.

The delivered price of grade 'F' coal, which is the coal used in thermal power stations, for selected distances has been estimated and is given in Table 3.3. It can be seen from the table that the transportation charge is a major component of the delivered price of coal. The share of transportation charge in the delivered price of coal increase from 16% for a 100 km haul to 28% for a 250 km haul, and becomes 47% for a 600 km haul. Figure 3.6 shows the share of the various components in the delivered price of grade 'F' coal. Table 3.3 also gives the delivered price of coking coal and grade 'D' coal for selected distances.

The Government of India has completely decontrolled the pricing of all grades of coal except grades 'E', 'F' and 'G'. For these grades, the government has allowed the subsidiary coal companies of Coal India Limited to fix the price of power grade coals for themselves. What this means is that the different subsidiaries of CIL may have different prices based on their cost of production. These prices would be reviewed every six months by updating the cost indices as per the escalation formula contained in the 1987 report of the Bureau of Industrial Costs and Prices (BICP).

The government has decided that the prices of 'E', 'F' and 'G' grade coal will also be decontrolled by January 2000 and set free from the BICP formula. What this means is that in the future, as the prices are completely decontrolled, they are expected to rise as the subsidiaries of CIL will enjoy a monopoly in the regions they serve. This is borne out by an analysis of the behaviour of the prices of superior grades of coal, which showed an increase of around 45% after decontrol, as opposed to annual increases of around 10% when administered.

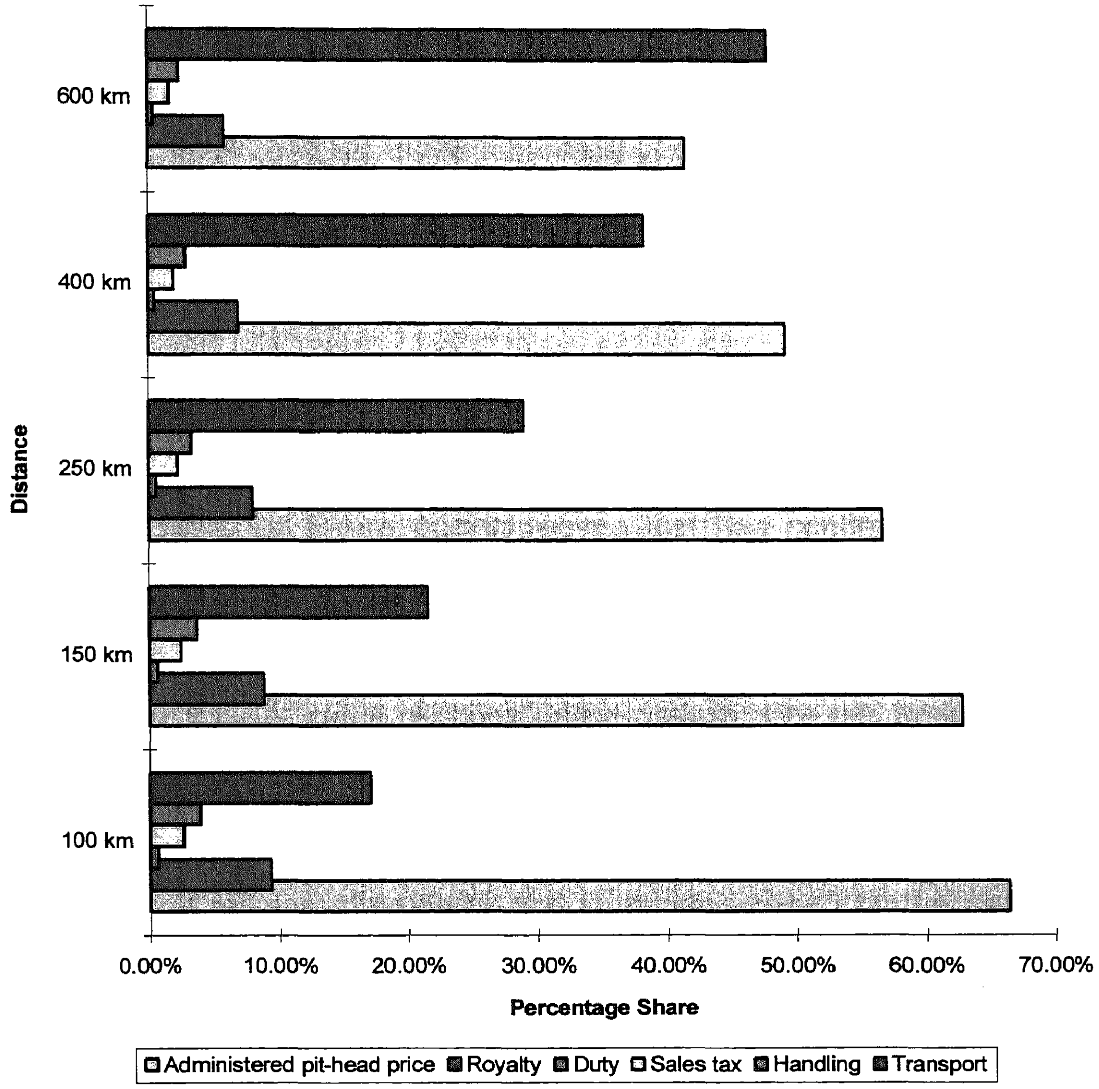
For the purpose of comparison, domestic power grade coal's pit-head price is about $ 0.61/MMBtu, while the c.i.f. price for imported coal is about $ 2.22/MMBtu.

Table 3.3: Delivered price of different grades of coal for selected distances

(Rs./ton)

Components	**100 km**	**150 km**	**250 km**	**400 km**	**600 km**
Grade 'F' for power generation					
Administered pit-head price	357.00	357.00	357.00	357.00	357.00
Royalty	50.00	50.00	50.00	50.00	50.00
Stowing excise duty	3.50	3.50	3.50	3.50	3.50
Sales tax (4%)	14.28	14.28	14.28	14.28	14.28
Mine handling charges	21.00	21.00	21.00	21.00	21.00
Total Pit-head price	445.78	445.78	445.78	445.78	445.78
Rail transport	92.00	123.00	183.00	278.00	412.00
Delivered price to consumer	**537.78**	**568.78**	**628.78**	**723.78**	**857.78**
Delivered price in $/MMBtu	**0.92**	**0.98**	**1.08**	**1.24**	**1.47**
Coking coal for steel plants					
Administered pit-head price	1246.00	1246.00	1246.00	1246.00	1246.00
Royalty	195.00	195.00	195.00	195.00	195.00
Stowing excise duty	3.50	3.50	3.50	3.50	3.50
Sales tax (4%)	49.84	49.84	49.84	49.84	49.84
Mine handling charges	21.00	21.00	21.00	21.00	21.00
Total Pit-head price	1515.34	1515.34	1515.34	1515.34	1515.34
Rail transport	95.84	130.33	193.18	288.39	435.03
Delivered price to consumer	**1611.18**	**1645.67**	**1708.52**	**1803.73**	**1950.37**
Delivered price in $/MMBtu	**1.31**	**1.34**	**1.39**	**1.46**	**1.58**
Grade 'D' for cement plants and refractories					
Administered pit-head price	804.00	804.00	804.00	804.00	804.00
Royalty	70.00	70.00	70.00	70.00	70.00
Stowing excise duty	3.50	3.50	3.50	3.50	3.50
Sales tax (4%)	32.16	32.16	32.16	32.16	32.16
Mine handling charges	21.00	21.00	21.00	21.00	21.00
Total Pit-head price	930.66	930.66	930.66	930.66	930.66
Rail transport	104.37	142.00	212.62	318.37	481.19
Delivered price to consumer	**1035.03**	**1072.66**	**1143.28**	**1249.03**	**1411.85**
Delivered price in $/MMBtu	**1.24**	**1.29**	**1.37**	**1.50**	**1.69**

Figure 3.6: Share of different components in delivered price of grade 'F' coal



3.2.3. Hydrocarbons

Pricing of crude oil and petroleum products in India was based on the concept of "import parity" until the first oil crisis in 1973. The consumer prices were related to the notional C.I.F. value of imported products and, in addition, included excise/custom duties, marketing and distribution margins and profits of oil companies. A number of committees were set up during the 1960s to examine the question of petroleum product pricing. All these committees recommended continuance of the "import parity" concept, though computation of the notional FOB prices of petroleum products for determining the final consumer prices varied from time to time.

The first change in this system of "import parity" prices was brought about in 1974 following the steep increase in crude oil prices in the international market. Until then, domestic producers were allowed a price in line with the prices prevailing in the international market. However, the indigenous producers were not allowed higher international prices from 1974 onwards and the prices they were paid were pegged at the earlier level. This led to the beginning of crude pool price concept (i.e. pooling of the cost of imported and indigenous crude) for building up petroleum product prices and emergence of the Crude Oil Prices Equalisation (COPE) account for making adjustments in crude cost of refineries processing imported and indigenous crude.

The Oil Prices Committee (OPC) that was set up by the Government of India in 1974 submitted its reports in 1975 and 1976. The recommendations of this Committee formed the basis for a new pricing regime that has continued till now with small variations. The Committee took note of the changes that had taken place in respect of the quantum of indigenous crude production and domestic refining capacity and felt that the import parity principle did not reflect the inter-refinery differences in respect of the type of crude oils, production pattern, size and complexity. The OPC, therefore, recommended that the pricing of major petroleum products at the refinery points be based on domestic cost, i.e. retention concept, by taking into account the delivered cost of crude oil (which is a pooled cost of imported and indigenous crude oil), the cost of refining of crude oil and reasonable return on the capital employed. Such a retention concept was recommended for marketing activities as well. These recommendations were accepted by the Government and a regime of retention pricing was introduced in two stages in 1975 and 1977 replacing the system based on the principle of import parity. This system continues to be in practice with certain variations till now. Essentially, the present pricing regime is a "cost plus" system worked out on the basis of normative costs plus a return on net worth/capital employed. This pricing system is applicable to different operations starting from upstream oil production to marketing and distribution of products. The costs of operations of different companies are "pooled" to ensure that the product prices from the storage points (the primary pricing points) are the same irrespective of the sources from which they come, and that price of any product at any location is the same for all companies marketing at that location.

3.2.3.1. *Pricing of crude oil*

The national oil companies, i.e. Oil & Natural Gas Corporation (ONGC) and Oil India Limited (OIL) engaged in exploration and production of oil and gas, are allowed a 15% post tax return on capital employed after taking into account normative costs of production, survey and development drilling expenditure, amortised exploratory drilling expenditure and depreciation of assets. Crude oil is currently priced at Rs 3469/ton ($ 99.11/ton) inclusive of royalty (Rs 578/ton) and cess (Rs 900/ton).

3.2.3.2. *Prices of products at refinery points*

Like the producing companies, the refineries in the country are also allowed retention prices for each ton of product. For the purpose of calculating the retention price for the products for each refinery, a standard throughput and standard product pattern (including refinery-specific fuel & loss) is decided for each refinery after taking note of crude processing capacity and the likely crude mix, secondary processing facilities available, and other relevant technical factors. Costs are also determined on a normative basis for each refinery separately for chemicals, catalysts, consumables, utilities, salaries and wages, overheads, depreciation, repairs and maintenance. The refineries are allowed a 12% post tax return on the net worth (equity plus reserves), the normative refining costs and the cost of crude oil. While the retention price per metric ton of crude throughput is so determined for each refinery, this retention price per ton of crude throughput is allocated to different petroleum products on the basis of a set of relative indices (e.g. kerosene 1.0, LPG 1.15, gas oil 0.95). This set of indices for different products under the controlled pricing system is uniform for all refineries. However, as the product pattern, the capital stock, as also the costs differ from refinery to refinery, the prices that the refineries are entitled for any particular petroleum product differ between refineries in spite of application of a uniform set of indices on the retention price per ton of crude throughput. In case the refineries are able to increase their crude throughput over the standard throughput, they are allowed, as an incentive, the same retention price (including return on the net worth) for the incremental quantity, though such incremental output involves incremental variable cost only. Conversely, there is a similar penalty if the throughput is lower than the standard throughput.

In short, while the delivered cost of crude oil is equalised by and large for all the refineries in the country, the retention price for each ton of crude throughput and then for each ton of petroleum product vary considerably from refinery to refinery depending upon the capital stock, the secondary processing facilities, the product pattern, the total refining capacity and other costs.

These different retention prices for each petroleum product for different refineries are thereafter pooled on a weighted basis to arrive at a uniform ex-refinery price for each petroleum product throughout the country.

3.2.3.3. Marketing and distribution charges

While the ex-refinery prices for each product are uniform, a similar pooling arrangement is made for working out the marketing and distribution margins. Normative estimates are made for each marketing company for installation, distribution and administration costs on the basis of expected throughput of each company. Besides, allowances are made for stock losses as also for operating expenses. Finally, a 12% post-tax return is allowed on the net fixed assets, in addition to interest on the borrowed capital. These retention prices for marketing companies are pooled and a uniform marketing margin is added to the ex-refinery prices for each product.

3.2.3.4. Other adjustments

Freight Surcharge Pool (FSP) Amount

This surcharge is levied on each product to meet the cost of transportation of products by coastal tankers, barges, pipelines and other transportation costs not specifically allowed.

Cost and Freight (C&F) Surcharge

This surcharge is mainly levied to recover the higher cost of imported products. In effect, this surcharge allows pooling the cost of domestic and imported products.

Product Price Adjustment (PPA)

These adjustment for each product are essentially decided on the basis of the Government's decision for cross subsidisation of products. The following approach has been followed for different products through such price adjustments:

i) As Kerosene is used mostly by relatively less affluent people, its price has been kept low.

ii) Prices of Naphtha and Fuel Oil for fertiliser production have been kept low to restrict the cost of fertiliser produced; the prices of these products are much higher for non-fertiliser use.

iii) Similarly, LPG prices for domestic use are kept much lower than LPG prices for commercial or industrial uses.

iv) Prices of Gasoline and Jet Fuel are higher to provide the cross-subsidisation on the products mentioned above.

Consumer prices

The prices ex-storage points thus include the following :

i) Ex-refinery price
ii) Excise duties
iii) Marketing Margin
iv) FSP
v) C&F surcharge
vi) PPA

Prices at ports, pipeline terminals and tap. off points, and upcountry installations and depots are arrived at by adding the appropriate coastal, pipeline or rail transportation cost to the ex-refinery price.

The final consumer price consists of ex-storage price and local taxes plus in the case of LPG, gasoline and gas oil retailing charges and local delivery costs from the storage point to the consumption point.

Table 3.4: Prices of hydrocarbons (ex-refinery gate) w.e.f. July 1996

Product	Selling unit	Basic ceiling selling price		
		Rupees	**US Dollars**	**$/MMBtu**
Liquefied petroleum gas				
For domestic	MT	6902	197	4.60
For non-domestic	MT	13900	397	9.27
Naphtha				
For non-fertilisers	MT	6683	191	4.56
For fertilisers	MT	4840	138	3.30
Gasoline	KL	22050	630	20.35
Kerosene				
For domestic	KL	2001	57	1.74
For industrial	KL	6519	186	5.67
Gas oil (HSD)	KL	6575	188	5.31
Fuel oil				
For non-fertilisers	KL	5896	168	4.35
For fertilisers	KL	3656	104	2.70

Notes: 1. These prices are exclusive of Customs and Excise duties, and also state sales tax.
2. The conversion rate has been taken as Rs 35/US $

Table 3.5: Duties and taxes on petroleum products

Type of levy	Product	Unit	Amount
Cess	Crude	Rs/MMT	900.00
Royalty	Crude	Rs/MMT	578.00
Royalty	Natural gas	%	10.00
Customs duty	Crude	%	25.00
Customs duty	Natural gas	%	0.00
Customs duty	LPG	%	10.00
Customs duty	Gasoline	%	30.00
Customs duty	Naphtha (for fertiliser)	%	0.00
Customs duty	Naphtha (non-fertiliser)	%	0.00
Customs duty	Gas oil	%	30.00
Customs duty	Fuel oil (for fertiliser)	%	30.00
Customs duty	Fuel oil (non fertiliser)	%	30.00
Surcharge on imports	Crude	%	2.00
Surcharge on imports	Natural Gas	%	0.00
Surcharge on imports	LPG	%	2.00
Surcharge on imports	Gasoline	%	2.00
Surcharge on imports	Naphtha (for fertiliser)	%	0.00
Surcharge on imports	Naphtha (non-fertiliser)	%	0.00
Surcharge on imports	Gas oil	%	2.00
Surcharge on imports	Fuel oil (for fertilisers)	%	2.00
Surcharge on imports	Fuel oil (non-fertilisers)	%	2.00
Excise	Crude	%	0.00
Excise	Natural Gas	%	0.00
Excise	LPG	%	10.00
Excise	Gasoline	%	15.00
Excise	Naphtha (for fertiliser)	%	0.00
Excise	Naphtha (non-fertiliser)	%	15.00
Excise	Gas oil	%	15.00
Excise	Fuel oil (for fertilisers)	%	0.00
Excise	Fuel oil (non-fertilisers)	%	15.00

3.2.3.5. The impact

The current pricing regime introduced since the mid-1970s has enabled the oil companies to recover their costs so computed and obtain an assured return on the capital employed. The fact that practically all the hydrocarbon exploration and production companies as also the marketing and refining companies are owned by the Government has facilitated the linkages between prices at different stages ensuring that across the country the consumer price of a product is, by and large, the same except for transportation and delivery costs and local taxes/duties. About 90% by volume of the products sold in the country are under the purview of this

administered pricing system, while the pricing of the balance products are left to the marketing companies to decide. The adjustments of prices allowed to different companies for the purpose of pooling of these prices are done through a number of pool accounts administered by the Oil Coordination Committee, attached to the Ministry of Petroleum and Natural Gas. In the absence inadequate availability of alternate fuels like coal and electricity, petroleum products have acted as a "swing fuel" and their demands have not been significantly affected in the medium term even when price increases have taken place.

A degree of insulation of the domestic prices against the volatile nature of international oil and product prices has been achieved by pooling of the lower cost indigenous crude and the higher cost imported crude. However, the advantage of the lower pooled crude oil cost has not been passed on to the consumers on a uniform basis for all products because of the policy objectives of the Government. A system of cross-subsidy among different products has resulted in uneven increases in prices of different products over the years. Kerosene prices have thus hardly increased in the last few years. Naphtha and Fuel Oil prices for non-fertiliser use are about 38% and 60% higher than the corresponding prices for fertiliser use. The price of gasoline is more than double the gas oil price.

3.2.3.6. The emerging scene

The administered pricing regime has started undergoing some changes. Parallel marketing has now been allowed for kerosene, LPG, LSHS and Lubricants. Private parties are now free to import these products or base stocks and sell them through their own marketing network at prices they consider appropriate. Obviously, such prices will be determined by market forces without any directive of the Government. The ownership pattern in the oil sector is also changing. Parallel marketing has brought in new marketing companies in the private sector. New refining capacities are also being set up by private parties on their own or jointly with public sector oil companies. A number of companies have been given contracts for development of new oil and gas fields. Similarly, production sharing exploration contracts have been signed with private companies.

With the change in the structure of the oil industry and the new steps that have been taken, it is very likely that the regime of administered pricing will undergo significant changes in the coming years. However, such changes will be preceded by a very detailed examination by the Government of the implications of these changes for the consumer price levels as also for different activities in the oil sector.

CHAPTER 4
ENERGY DEMAND

4.1. ELECTRICITY

4.1.1. Existing demand

The final consumption of electricity in each state, as on March 31, 1995, disaggregated by market segment is given in Table 4.1. This is the latest data available.

Table 4.1: Final consumption of electricity disaggregated by market segment (1994-95)

(GWh)

	Electricity Sales						
				Industrial			
State	**Agriculture**	**Commercial**	**Domestic**	**Utilities**	**Captive**	**Subtotal**	***Total***
West Bengal	838	2459	2775	5571	1280	6851	*12923*
Orissa	361	820	1566	3579	6362	9941	*12688*
Andhra Pradesh	11270	1499	3320	7549	3291	10840	*26929*
Tamil Nadu	6296	3217	3928	10173	1482	11655	*25096*

Note: 1. 'Commercial' includes railway traction, public water works, street lighting, etc.
2. Utilities are entities which distribute electricity to ultimate consumers.
3. Captive means generation by industries for their own use.

Source: Ministry of Power and Central Electricity Authority, New Delhi

65% of the energy is consumed by Orissa's industrial sector is generated by industries themselves This is due to the presence of two large aluminium industries which generate their own electricity. One is the Indian Aluminium Company (Indalco) located at Hirakud with an installed capacity of 117,000 metric tons per year and the other is the National Aluminium Company (Nalco) at Anugul with an installed capacity of 107,000 metric tons per year.

Andhra Pradesh has a very high consumption of electricity in agriculture, even larger than that consumed by the state's industrial sector.

4.1.2. Projected demand

For the industrial and commercial sectors, the projections have been done by fitting a regression equation, taking the sectoral consumption as the dependent variable, and the corresponding sector's contribution to the State Domestic Product (SDP) as the independent variable. An overall annual growth rate of approximately seven

percent for India's gross domestic product (GDP) is used, and this forms the basis for the forecast of the rate of growth for the SDP.

Electricity consumption in sectors such as railway traction, street lighting, public water works, etc. have been clubbed together under the commercial sector as these activities are included under commerce. The captive generation capacity owned by the industries was added to the sales of electricity by the respective utilities to the industrial sector to obtain a truer picture of electricity requirements of industry.

In the case of the domestic sector, the sector's electricity consumption was taken as the dependent variable, and regressed against the population of the state. The electricity requirement projections in the case of the agriculture sector, were done by fitting a regression equation. The gross irrigated area in the state was taken as the independent variable, while the sector's electricity consumption was taken as the dependent variable.

Table 4.2 gives electricity demand disaggregated by sector for the four states.

4.1.2.1. West Bengal

At just over four times the 2000 level, the growth in the electricity requirements of the domestic sector in West Bengal is high in comparison to agriculture's requirements, which grow by about 1¾ times during the same period. The growth rate of commercial sector is 2.9 times while Industry grows to 2.3 times over the same period.

4.1.2.2. Orissa

Domestic sector's requirement of electrical energy shows a modest increase in Orissa between 2000 and 2015, growing about four times the 2000 level. The corresponding growth in the requirement of the agriculture sector is 2.45 times in comparison. Commerce and industry's electricity requirements grow at almost the same rate, the requirement in 2015 being around 3.8 times the 2000 levels.

4.1.2.3. Andhra Pradesh

The domestic sector's requirement of electrical energy in Andhra Pradesh shows a spectacular increase of over 5.5 times the year 2000 level by 2015. Overall growth in electricity requirements is limited to a factor of just over 3.25 times over the same period.

Table 4.2: Disaggregated electricity demand projections

(GWh)

Year	Agriculture	Commercial	Domestic	Industrial	Total
West Bengal					
1994	838	2459	2775	6851	12923
2000	1071	3281	5342	7906	17599
	(4.17%)	(4.92%)	(11.53%)	(2.42%)	(5.28%)
2005	1309	4377	8688	9779	24153
	(4.10%)	(5.94%)	(10.22%)	(4.34%)	(6.54%)
2010	1576	6442	14058	13304	35380
	(3.79%)	(8.03%)	(10.10%)	(6.35%)	(7.93%)
2015	1879	9419	22518	18389	52204
	(3.57%)	(7.90%)	(9.88%)	(6.69%)	(8.09%)
Orissa					
1994	361	820	1566	9941	12688
2000	524	2061	2809	16729	22123
	(6.41%)	(16.00%)	(10.23%)	(9.06%)	(9.71%)
2005	716	3095	4414	24911	33136
	(6.44%)	(8.47%)	(9.46%)	(8.29%)	(8.42%)
2010	963	5041	6959	40313	53276
	(6.10%)	(10.25%)	(9.53%)	(10.11%)	(9.96%)
2015	1284	7848	10900	62529	82561
	(5.93%)	(9.26%)	(9.39%)	(9.18%)	(9.16%)
Andhra Pradesh					
1994	11270	1499	3320	10840	26929
2000	14301	2065	7176	14652	38193
	(4.05%)	(5.48%)	(13.71%)	(5.15%)	(6.00%)
2005	17383	2884	13250	20733	54249
	(3.98%)	(6.91%)	(13.05%)	(7.19%)	(7.27%)
2010	20289	4425	23529	32182	80424
	(3.14%)	(8.94%)	(12.17%)	(9.19%)	(8.19%)
2015	23225	6648	40622	48695	119190
	(2.74%)	(8.48%)	(11.54%)	(8.64%)	(8.19%)
Tamil Nadu					
1994	6296	3217	3928	101655	24096
2000	7584	4938	7548	12085	32156
	(3.15%)	(7.40%)	(11.50%)	(2.12%)	(4.93%)
2005	8766	8023	12639	16905	46333
	(2.94%)	(10.19%)	(10.86%)	(6.94%)	(7.58%)
2010	10054	13564	20513	25561	69691
	(2.78%)	(11.07%)	(10.17%)	(8.62%)	(8.51%)
2015	11414	21386	32470	37869	103139
	(2.57%)	(9.53%)	(9.62%)	(8.18%)	(8.16%)

Note: Figures in parentheses indicate the average annual rate of growth in the preceding period.

4.1.2.4. Tamil Nadu

There is very low growth in the requirements of the industrial sector in the state between 1996 and 2000 but demand picks up after 2000. The domestic sector shows the maximum growth, growing by over 4.25 times between 2000 and 2015.

4.1.3. Installed capacity requirements

The total electricity requirement and the consequent installed capacity needed in the three states for the years 2000, 2005, 2010, and 2015 is given in Table 2.3.

The transmission and distribution (T&D) losses are assumed to show a decline over time, and the values for T&D losses in the year 2000 are taken as 20.5%, 22.4%, 18.0% and 15.5% for West Bengal, Orissa, Andhra Pradesh and Tamil Nadu respectively. These losses are assumed to decline to 17.5%, 19.4%, 16.5% and 14.0% by the year 2015 for the four states respectively.

The system load factor (SLF) is taken to be 71% to arrive at the maximum MW demand placed on the system from the total energy (GWh) requirements after T&D losses. Finally, a reserve margin is added to the expected maximum system demand to arrive at the projections for installed capacity. This reserve margin is of the order of 30% of the total installed capacity required[1].

The overall annual growth rate of the installed capacity requirements takes a jump of around 1% over the preceding rate of growth in the year 2005. Orissa has the highest rate of growth for installed capacity requirements amongst the three, reaching to almost 9% per annum for the period 2005 to 2015.

The rates of growth of the installed capacity requirements are lower than that of the total electricity consumption because of decreasing transmission and distribution losses over time.

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[1] The 'peak demand' is divided by 0.7 to obtain the 'installed capacity required'.

Table 4.3: Total electricity required and consequent installed capacity

Year	Energy (GWh)		Demand (MW)		Growth rate of inst. capacity since 2000
	Energy reqd. for all sectors	Energy reqd. with T&D loss	Peak demand (SLF = .71)	Installed capacity reqd.	
West Bengal					
2000	17599	22137	3559	5084	-
2005	24153	30004	4824	6891	6.27%
2010	35380	43411	6980	9971	7.67%
2015	52204	63278	10174	14534	7.83%
Orissa					
2000	22123	28509	4584	6549	-
2005	33136	42157	6778	9683	8.14%
2010	53276	66929	10761	15373	9.69%
2015	82561	102432	16469	23527	8.88%
Andhra Pradesh					
2000	38193	46577	7489	10698	-
2005	54249	65757	10573	15104	7.14%
2010	80424	96897	15579	22256	8.06%
2015	119190	142742	22950	32786	8.05%
Tamil Nadu					
2000	32156	38054	6118	8741	-
2005	46333	54510	8764	12520	7.45%
2010	69691	81510	13105	18722	8.38%
2015	103139	119929	19282	27546	8.03%

Table 4.4 gives the expected fuel-wise break-up of the installed capacities (utilities & captive) till 2015 in the three states. The fuel-mix was estimated on the basis of existing proposals and the likelihood of their being commissioned in a particular period. This assessment was based on a number of factors, including the current status of the projects with respect to clearances from the Central Electricity Authority, whether a power purchase agreement has been entered into with the state government or not, etc. Based on these factors, the projects which were at an advanced stage in the approval process were thought of as being likely to come up earlier than those which had just started the process of gaining the requisite approvals. For projects promoted by the government (whether state or central) the expected date of commissioning as indicated by the executing agency was followed.

Table 4.4: Fuel-mix of installed capacities (utilities & captive) till year 2015

(MW)

State[1]	Total	Hydro	Coal	Gas Oil[2]	Gas turbine[3]	Nuclear
West Bengal						
1996	5974	97	5316	438	123	0
2000	8229	97	7571	438	123	0
2005	10595	997	9037	438	123	0
2010	10914	997	9356	438	123	0
2015	11311	997	9753	438	123	0
Orissa						
1996	4166	1272	2741	121	32	0
2000	5729	1572	4004	121	32	0
2005	10364	1872	8339	121	32	0
2010	13050	1872	11025	121	32	0
2015	15909	1872	13884	121	32	0
Andhra Pradesh						
1996	7131	2656	3860	351	235	29
2000	7656	2656	4158	351	462	29
2005	8747	2656	4989	351	722	29
2010	9329	2656	5544	351	749	29
2015	10418	2656	6603	351	779	29
Tamil Nadu						
1996	7089	1948	4103	619	166	253
2000	8399	1948	4603	719	876	253
2005	9821	1948	5689	1019	912	253
2010	12909	2098	6888	1219	2451	253
2015	16453	2098	8890	1219	3993	253

Note:
1. The share of the states from centrally owned stations is included in the states' capacity.
2. These are reciprocating engines being run on gas oil or fuel oil.
3. They are using naphtha or gas oil as per availability of the fuel.

The plant-wise break-up of the new capacities and the expected period of commissioning are given in Table 4.5 for the four states.

Table 4.5: New power stations expected to be commissioned

Name	Type	Total	Capacity Expected			
		Capacity (MW)	2000	2005	2010	2015
West Bengal						
Sagardighi	Coal	1000	-	1000	-	-
Ballagarh	Coal	500	500	-	-	-
Mejia	Coal	420	420	-	-	-
Budge Budge	Coal	500	500	-	-	-
Bakreshwar	Coal	1050	630	420	-	-
Puruliya	Hydro	900	-	900	-	-
Orissa						
Ib Valley 3&4	Coal	420	420	-	-	-
Dhuburi	Coal	500	-	500	-	-
Hirma	Coal	3960	-	1980	1980	-
Bomlai	Coal	500	-	500	-	-
Lapanga	Coal	500	-	-	500	-
Indravati	Hydro	600	300	300	-	-
Andhra Pradesh						
Godavari	Naphtha	208	208	-	-	-
Jegurupaddu II	Gas	235	-	235	-	-
Krishnapatnam A	Coal	500	-	-	500	-
Krishnapatnam B	Coal	500	-	-	-	500
Ramagundam	Coal	500	-	-	-	500
Vishakhapatnam	Coal	1040	260	780	-	-
Tamil Nadu						
North Madras	Coal	210	210	-	-	-
Basin Bridge	Gas	120	120	-	-	-
North Madras II	Coal	1050	-	1050	-	-
Pillai Peru Malnallur	Gas	330	330	-	-	-
Neyveli Zero Unit	Lignite	250	250	-	-	-
Various places	Fuel Oil	400	100	300	-	-
Cuddalore	Coal	1320	-	-	660	660
North Madras	Coal	500	-	-	500	-
Basin Bridge	Fuel Oil	220	220	-	-	-
Samalpatti	Fuel Oil	100	-	-	100	-
Somayanallur	Fuel Oil	100	-	-	100	-
Gummidipoondi	Gas	1000	-	-	1000	-
Vembar	Gas	2000	-	-	500	1500
Pykara	Hydro	150	-	-	150	-
Tuticorin	Coal	500	-	-	-	500
Jayamkondam	Lignite	550	-	-	-	550
Srimusham	Lignite	250	-	-	-	250

Table 4.6: Comparison of capacity requirement with expected capacity

(MW)

	Installed capacity required	Expected installed capacity	Surplus/Deficit
West Bengal			
2000	5084	8229	3145
2005	6891	10595	3704
2010	9971	10914	943
2015	14534	11311	(-)3223
Orissa			
2000	6549	5729	(-)820
2005	9683	10364	681
2010	15373	13050	(-)2323
2015	23527	15909	(-)7618
Andhra Pradesh			
2000	10698	7656	(-)3042
2005	15104	8747	(-)6357
2010	22256	9329	(-)12927
2015	32786	10418	(-)22368
Tamil Nadu			
2000	8741	8399	(-)342
2005	12520	9821	(-)2699
2010	18722	12909	(-)5813
2015	27546	16453	(-)11093

It must also be mentioned that though it appears as though the electricity requirements are met by the expected installed capacity in West Bengal in the initial stages, this may not be true in reality. The thermal power stations owned by the West Bengal State Electricity Board are operated at a very low load factor (less than 35%). This has lead to a situation where the installed capacity is more than the requirement, but the SEB has to import power to meet its average electricity demand. If the same situation continues in the future, the installed capacity required to feed the electricity demand will be much more than what has been presented here.

4.2. COAL

4.2.1. Existing demand

The three states of West Bengal, Orissa and Andhra Pradesh account for a large share of the coal reserves in the country. Tamil Nadu has lignite reserves located in the Neyveli area to the south of Madras.

The current demand for coal, broken down by the major consumer sectors; is given in Table 4.7. There are two columns under "thermal power stations". One gives the actual value of coal consumption in this sector, while the second column gives the calculated value. The calculated value is the coal consumption which would occur in the thermal power stations if they were running at a plant load factor of 68.5%. The total consumption given in the table is based on the actual consumption of coal in the states.

The actual consumption of coal in power stations located in West Bengal and Orissa is much lower than the calculated consumption because the state sector power stations currently operate at a very low PLF (about 35%), and some large central sector power stations like Talcher (1000 MW) and Mejia (210 MW), have only been commissioned in 1995-96, and have operated for part of the year.

Since the projections of coal demand in the power sector are based on thermal power stations operating at a PLF of 68.5%, it would be more appropriate to compare the forecasted values with current consumption calculated at a comparative PLF rather than the actual.

Table 4.7: Existing demand for coal as on March 31, 1996

(million tons/year)

State	**Thermal Power Station**[1]		**Iron & Steel Plant**	**Cement Plant**	**Fertiliser**	**Total**
	Actual[2]	*Calculated*[2]				
West Bengal	16.42	21.26	4.20	0.01	0.00	20.63
Orissa	2.99	10.96	2.64	0.25	0.71	6.59
Andhra Pradesh	15.02	15.44	0.96	1.91	0.00	17.89
Tamil Nadu	19.32	19.68	0.00	1.15	0.00	20.47
TOTAL	**53.75**	**67.34**	**7.80**	**3.32**	**0.71**	**65.58**

Note: 1. Both utility owned and captive power plants are included under thermal power stations.
2. Please see explanation preceding Table 2.7.

4.2.2. Projected demand

The demand projections in the power sector have been done on the basis of the expected fuel mix in the future. While the iron & steel industry is expected to grow at a rate of around 7.50% annually, the coal demand in this sector is expected to grow at a slower pace because of increasing efficiency in steel production. The cement industry, and its coal demand, is expected to achieve a growth rate of about 1.75%. There is currently one fertiliser plant located at Talcher in Orissa which is based on coal, and another one is expected to come up by the year 2005.

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Table 4.8 gives the projected coal demand in the states of West Bengal, Orissa, Andhra Pradesh and Tamil Nadu till the year 2015.

Table 4.8: Coal demand projections

(million tons/year)

Year	**1995**	**2000**	**2005**	**2010**	**2015**
West Bengal					
Thermal Power Station	21.26	30.28	36.15	37.42	39.01
Iron/Steel Plant	4.20	6.03	8.26	10.80	13.78
Cement Plant	0.01	0.01	0.01	0.01	0.01
Fertiliser	0.00	0.00	0.00	0.00	0.00
Total	**25.47**	**36.32**	**44.42**	**48.23**	**52.80**
Orissa					
Thermal Power Station	10.96	16.02	33.36	44.10	55.54
Iron/Steel Plant	2.64	3.79	5.19	6.78	8.65
Cement Plant	0.25	0.27	0.30	0.32	0.35
Fertiliser	0.71	0.71	1.77	1.77	1.77
Total	**14.56**	**20.79**	**40.62**	**52.97**	**66.31**
Andhra Pradesh					
Thermal Power Station	15.44	16.63	19.96	22.18	26.41
Iron/Steel Plant	0.96	1.38	1.89	2.47	3.15
Cement Plant	1.91	2.08	2.27	2.48	2.70
Fertiliser	0.00	0.00	0.00	0.00	0.00
Total	**18.31**	**20.09**	**24.12**	**27.13**	**32.26**
Tamil Nadu					
Thermal Power Station	19.68	20.97	22.76	27.55	35.56
Iron/Steel Plant	0.00	0.00	0.00	0.00	0.00
Cement Plant	1.15	1.25	1.37	1.49	1.63
Fertiliser	0.00	0.00	0.00	0.00	0.00
Total	**20.83**	**22.22**	**24.13**	**29.04**	**37.19**
Note: Both utility owned and captive power plants are included under thermal power stations.					

4.3. HYDROCARBONS

4.3.1. Existing demand

4.3.1.1. West Bengal

Both agriculture and industry play a pivotal role in the state's economy. West Bengal consumes 3.46 MMT of petroleum products accounting for 5.5 percent of the national total. The per capita consumption of 49 kilograms for 1993-94 is the highest amongst the three states. Tables 4.9 and 4.10 respectively show the consumption of petroleum products and the sector-wise demand for petroleum products in 1994-95.

Table 4.9: Consumption of petroleum products in West Bengal

('000 metric tons)

Product	1990-91	1991-92	1992-93	1993-94	1994-95	RoG since 1990-91
LPG	125	135	148	159	176	7%
Gasoline	150	144	142	144	150	0%
Naphtha	74	9	70	40	4	-44%
Kerosene	752	736	750	761	782	1%
Jet Fuel	110	111	101	108	114	1%
Gas oil	1463	1516	1579	1541	1653	2%
Fuel oil	328	301	265	322	294	-2%
Others	423	370	318	265	290	-7%
Total	**3425**	**3322**	**3373**	**3340**	**3463**	**0%**

Table 4.10: Sector-wise demand for petroleum products in West Bengal in 1994-95

('000 metric tons)

	Domestic	Transport	Industry					Misc.	Total
			Power	Fertiliser	Iron & Steel	Others	Subtotal		
LPG	158	-	-	-	-	-	-	18	176
Gasoline	-	150	-	-	-	-	-	-	150
Naphtha	-	-	-	4	-	-	4	-	4
Kerosene	782	-	-	-	-	-	-	-	782
Jet Fuel	-	114	-	-	-	-	-	-	114
Gas oil	-	1578	75	-	-	-	75	-	1653
Fuel oil	-	-	34	3	20	237	294	-	294
Others	-	-	-	-	-	-	-	-	290
Grand Total									**3463**

4.3.1.2. Orissa

Agriculture plays a vital role in Orissa's economy providing 80 percent of rural employment and enriching the state domestic product by 59 per cent. Orissa consumed 2% of all India petroleum products in the year 1994-1995. The per capita consumption of petroleum products for Orissa has been growing at a rate of 3% and stands at 40 kilograms compared to the national average of 75 kilograms for the year 1994-1995. Tables 4.11 and 4.12 respectively show the growth of consumption of petroleum products in Orissa and their end use-wise break up.

Table 4.11: Consumption of petroleum products in Orissa

('000 metric tons)

Product	1990-91	1991-92	1992-93	1993-94	1994-95	RoG since 1990-91
LPG	20	23	25	31	35	12%
Gasoline	54	55	56	59	63	3%
Naphtha	108	92	108	123	105	-1%
Kerosene	156	155	156	175	204	6%
Jet Fuel	13	12	13	9	9	-7%
Gas oil	449	488	518	554	604	6%
Fuel oil	245	274	288	262	285	3%
Others	80	98	76	62	69	-3%
Total	**1125**	**1197**	**1240**	**1275**	**1374**	**4%**

Table 4.12: Sector-wise demand for petroleum products in Orissa in 1994-95

('000 metric tons)

	Domestic	Transport	Industry					Misc.	Total
			Power	Fertiliser	Iron & Steel	Others	Subtotal		
LPG	32	-	-	-	-	-	-	3	35
Gasoline	-	63	-	-	-	-	-	-	63
Naphtha	-	-	-	105	-	-	105	-	105
Kerosene	204	-	-	-	-	-	-	-	204
Jet Fuel	-	9	-	-	-	-	-	-	9
Gas oil	-	600	4	-	-	-	4	-	604
Fuel oil	-	-	7	6	63	209	285	-	285
Others	-	-	-	-	-	-	-	-	69
Grand Total									**1374**

4.3.1.3. Andhra Pradesh

Agriculture is the main occupation of about 70 per cent of the people in Andhra Pradesh, and about 40 per cent of the cultivated area is irrigated. Several major industries are located here. The state also is well endowed in various mineral including coal and petroleum. The per capita consumption of petroleum products is growing at a rate of 6% since 1990-95, standing at 63 kilograms as against a national average of 75 kilograms. Andhra Pradesh accounts for a total of 6% of the national POL consumption. Tables 4.13 and 4.14 respectively show the growth of consumption of petroleum products in Andhra Pradesh and their end use-wise break up.

Table 4.13: Consumption of petroleum products in Andhra Pradesh

('000 metric tons)

Product	**1990-91**	**1991-92**	**1992-93**	**1993-94**	**1994-95**	**RoG since 1990-91**
LPG	181	202	213	235	254	7%
Gasoline	217	220	225	242	270	4%
Naphtha	78	53	60	75	79	0%
Kerosene	576	565	582	591	598	1%
Jet Fuel	43	39	35	41	36	-3%
Gas oil	1760	1906	2141	2223	2453	7%
Fuel oil	295	258	269	286	302	0%
Others	189	201	226	238	218	3%
Total	**3339**	**3444**	**3751**	**3931**	**4210**	**5%**

Table 4.14: Sector-wise demand for petroleum products in Andhra Pradesh in 1994-95.

('000 metric tons)

	Domestic	**Transport**	**Industry**					**Misc.**	**Total**
			Power	**Fertiliser**	**Steel**	**Others**	**Subtotal**		
LPG	230	-	-	-	-	-	-	24	254
Gasoline	-	270	-	-	-	-	-	-	270
Naphtha	-	-	-	78	-	-	78	1	79
Kerosene	598	-	-	-	-	-	-	-	598
Jet Fuel	-	36	-	-	-	-	-	-	36
Gas oil	-	2446	7	-	-	-	7	-	2453
Fuel oil	-	-	22	23	10	247	302	-	302
Others	-	-	-	-	-	-	-	-	218
Grand Total									**4210**

4.3.1.4. Tamil Nadu

Oil consumption in Tamil Nadu is the highest among the four states. The consumption at 5.6 MMT in 1994-95 accounts for 9% of the all-India consumption. The product-wise consumption over the 5 years till 1994-95 is shown in Table 4.15 and the end use wise break up of the products in Table 4.16.

Table 4.15: Consumption of petroleum products in Tamil Nadu

('000 metric tons)

Product	1990-91	1991-92	1992-93	1993-94	1994-95	RoG since 1990-91
LPG	204	220	238	257	285	7%
Gasoline	238	241	244	262	291	4%
Naphtha	461	493	472	443	487	1%
Kerosene	656	642	662	666	671	0%
Jet Fuel	50	58	60	71	84	11%
Gas oil	2064	2150	2195	2285	2488	4%
Fuel oil	830	876	870	869	904	2%
Others	311	337	354	360	417	6%
Total	**4814**	**5017**	**5095**	**5209**	**5627**	**3%**

Table 4.16: Sector-wise demand for petroleum products in Tamil Nadu in 1994-95

('000 metric tons)

	Domestic	Transport	Industry					Misc.	Total
			Power	Fertiliser	Petro-chemical	Others	Sub-total		
LPG	257	-	-	-	-	-	-	28	285
Gasoline	-	291	-	-	-	-	-	-	291
Naphtha	-	-	-	484	3	-	487	-	487
Kerosene	671	-	-	-	-	-	-	-	671
Jet Fuel	-	84	-	-	-	-	-	-	84
Gas oil	-	2481	7	-	-	-	7	-	2488
Fuel oil	-	-	47	335	47	475	904		904
Others	-	-	-	-	-	-	-	-	417
Grand Total									**5627**

4.3.2. Projected demand

Product-wise demand projections to 2006/07 have been carried out by the Oil Co-ordination Committee (OCC) in 1994. This study has used those projections and has extrapolated them to 2015 after consultation with oil industry experts about the future growth potentials in the various states.

OCC was commissioned by the Ministry of Petroleum and Natural Gas to assess product-wise demand and had a broad based representation from the Planning Commission, Ministry of Surface Transport, Department of Fertilisers, Department of Chemicals, Ministry of Steel, and Ministry of Power.

OCC followed various methodologies in the forecasting exercise. While for the purpose of forecasting LPG demand, state-level field surveys were conducted, for products like naphtha and fuel oil, an end-use based approach was adhered to. End-use consumption of fuel oil was analysed and it was found that bulk of the product is consumed in the power, fertiliser, and petrochemical industry. Based on the planned growth of these industries in each state, projections of fuel oil demand have been made. The demand projections for petroleum products in the four states are shown in Table 4.17.

Table 4.17: Projected demand of petroleum products

('000 metric tons)

Year	2000	2005	2010	2015	RoG since 2000
West Bengal					
LPG	339	492	609	752	5.46%
Gasoline	247	361	515	723	7.42%
Naphtha	124	1624	1624	1624	18.71%
Kerosene	1002	1162	1346	1607	3.20%
Gas oil	2546	3659	4506	5553	5.34%
Fuel oil	406	491	604	735	4.04%
Orissa					
LPG	66	96	136	200	7.67%
Gasoline	103	151	216	302	7.43%
Naphtha	140	140	148	164	1.06%
Kerosene	262	304	352	408	3.00%
Gas oil	943	1366	1942	2723	7.33%
Fuel oil	519	584	648	716	2.17%
Andhra Pradesh					
LPG	497	840	1087	1142	5.70%
Gasoline	448	649	952	1398	7.88%
Naphtha	88	88	90	95	0.51%
Kerosene	674	766	854	943	2.26%
Gas oil	3761	5386	7800	11460	7.71%
Fuel oil	402	525	647	826	4.92%
Tamil Nadu					
LPG	612	713	806	938	2.89%
Gasoline	427	632	927	1362	8.04%
Naphtha	521	521	543	572	0.62%
Kerosene	619	629	637	683	0.66%
Gas oil	3489	4620	6101	8049	5.73%
Fuel oil	595	643	738	854	2.44%

4.4. SALES POTENTIAL OF NATURAL GAS

4.4.1. Power sector

The gas requirement for a power plant has been taken as 1.04 million cubic meter (MCM) per year for every megawatt of installed capacity, assuming a plant load factor of 68.5% and the calorific value of gas as 8760 kilo calories/Nm^3.

Table 4.18 gives the potential for sale of natural gas in the power sector in the four states.

Table 4.18: Natural gas sales potential in power sector

	Capacity (MW)					Gas Requirement (MCM/year)[2]
	IPP owned	**Captive**	**Gas/liquid fuel based**	**Deficit**	**Total**	
West Bengal						
2000	-	-	428	-	428	445.12
2005	333	85	428	-	846	879.84
2010	333	192	428	-	953	991.12
2015	333	324	428	1074	2159	2245.36
Orissa						
2000	-	-	91	-	91	94.64
2005	993	452	91	-	1536	1597.44
2010	1820	1010	91	774	3695	3842.80
2015	1820	2183	91	2539	6633	6898.32
Andhra Pradesh						
2000	-	-	813	-	813	845.52
2005	-	17	1073	2119	3309	3441.36
2010	-	35	1100	6528	7663	7969.52
2015	-	55	1130	13984	15169	15775.76
Tamil Nadu						
2000	-	-	1595	-	1595	1658.80
2005	350	12	1931	900	3193	3320.72
2010	737	25	3670	2838	7270	7560.80
2015	1424	39	5212	6536	13211	13739.44
Total						
2000	-	-	2927	-	2927	3044.08
2005	1676	566	3523	3019	8884	9239.36
2010	2890	1262	5289	10140	19581	20364.24
2015	3577	2601	6861	24133	37172	29515.20

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[2] Assuming 1520 kcal are required to produce 1 kWh, 68.5% PLF, and calorific value of gas as 8760 kcal/Nm^3.
[(68.5% * 1520 kcal/kWh * 8760 hours/year * 1000 kW/MW) / (8760 kcal/Nm^3 * 1000000 Nm^3/MCM)]
= 1.04 MCM/year per MW.

The natural gas requirement has been derived from the installed capacities of the power stations located in the study area and expected to be based on gas or liquid fuels. This was done as power stations (utility owned or captive) using gas oil, fuel oil or naphtha can switch to using natural gas without major modifications, and it has been assumed that all power stations using these fuels would switch to gas if it were made available at a competitive price. In addition, it has been broadly assumed that one-third of the following would be amenable to using natural gas.

1. Any power plant owned by an Independent Power Producer (IPP) and due to come up after 2000. (These would need to redesign their plants to use gas turbines instead of steam turbines.)
2. All captive power plants located in the study area and due to come up after 2000.
3. Any deficit in installed capacity (beyond 2000).

4.4.2. Iron & steel

The region (except Tamil Nadu) is a major centre for iron & steel industries. West Bengal hosts two integrated steel plants, the Durgapur Steel Plant at Durgapur and the Indian Iron and Steel Company (IISCO) at Burnpur, while Orissa and Andhra Pradesh have one each, the Rourkela Steel Plant at Rourkela (Orissa), and the Vishakhapatnam Steel Plant (VSP) at Vishakhapatnam (Andhra Pradesh). All the plants except VSP are operated by the Steel Authority of India Limited (SAIL).

The Calcutta-Howrah region is famous for its foundries and boasts of about 70% of the country's total installed capacity. These foundries together consume more than half a million ton of coal every year which could be substituted by natural gas.

The foundries located in the area have had to install expensive pollution control equipment in order to continue operations, and most owners feel that the requirements would only get more stringent over the years. Senior officers of the Howrah Foundry Association and the Indian Foundry Association have indicated that they would be very much interested in switching to a cleaner fuel source so as to take care of the problem of pollution once and for all.

Table 4.19: New iron and steel units

Name	District	Capacity (MMT/year)		Status	Proposed start date
		Steel	Pig Iron		
WEST BENGAL					
Gontermann-Peipers (India)	S. 24 Parganas	0.03	-	Under Impl.	1997-98
Birla Technical Services	Barddhaman	0.32	-	N/A	2001-02
Birla Metals	Medinipur	-	0.30	Announced	N/A
Century Textiles & Industries	Medinipur	-	0.30	Proposed	N/A
Iron & Steel Industry	Barddhaman	-	0.50	Proposed	N/A
Durgapur Projects	Barddhaman	-	0.60	Proposed	N/A
Birla Technical Services	Barddhaman	-	5.57	N/A	N/A
Kajaria Iron Castings	Barddhaman	-	0.90	N/A	N/A
ORISSA					
Mesco Kalinga Steel	Kendujhargarh	1.30	0.50	Under Impl.	1997-98
Mideast Int. Steel	Cuttack	0.96	0.50	Under Impl.	1997-98
Ganapati Iron & Steel Co.	Kendujhargarh	2.50	1.00	Announced	1998-99
Nilachal Ispat Nigam	Kendujhargarh	0.80	0.20	Proposed	1998-99
Nilachal Ispat Nigam Ltd	Cuttack	0.94	-	N/A	1998-99
Brahmani Iron & Steel Co	Cuttack	0.30	-	N/A	1998-99
Bhushan Steel & Strips Ltd	Cuttack	0.65	-	N/A	1999-2000
Bhushan Steel & Strips Ltd	Cuttack	0.75	-	N/A	2001-02
Bhushan Steels & Strips	Cuttack	0.70	-	Announced	N/A
Ind. Seamless Steels & Alloys	Kendujhargarh	1.25	-	Announced	N/A
Asian Alloys	Kendujhargarh	0.42	-	Proposed	N/A
Mideast Int. Steel	Cuttack	-	0.70	Proposed	N/A
Jindal Strips	Dhenkanal	0.15	-	Proposed	N/A
Jindal Ferro Alloys	Dhenkanal	0.46	-	N/A	N/A
Mesco Kalinga Steel Ltd	Cuttack	2.25	-	N/A	N/A
Nilachal Ispat Nigam Ltd	Cuttack	-	2.00	N/A	N/A
SAIL	Sundargarh	3.60	-	N/A	N/A
Bhushan Steel & Strips Ltd	Cuttack	0.60	0.20	N/A	N/A
ANDHRA PRADESH					
SJK Steel Corp.	Anantapur	0.27		Under Impl.	1997-98
Vishnupriya Ind.	Kurnool	0.15		Under Impl.	1997-98
Rashtriya Ispat. Nigam	Vishakhapatnam	1.00		Proposed	

In addition, there are about 350 rolling mills located in the Howrah region accounting for a total coal consumption of 250 thousand tons per year. These mills would also be amenable to a switch to natural gas if made available at competitive prices.

It is estimated by the Steel Authority of India Limited (SAIL) that the iron & steel industry would double its output in about seven years, achieving an annual growth rate of over 10%. For the purpose of this study, a more conservative figure of 7.5% has been assumed. Table 4.19 lists some new units which have been announced in the study region.

4.4.2.1. Potential for natural gas sales

The iron & steel industry consumes some amount of fuel oil which can be replaced by natural gas without much difficulty. Of the total consumption of fuel oil in the three steel producing states, iron & steel industries have a share of 7%, 22% and 3% in West Bengal, Orissa and Andhra Pradesh respectively. Assuming the same shares to continue in the future, and using a natural gas equivalent of 1.19 MCM for every thousand tons of fuel oil, the natural gas sales potential in the iron & steel industry is calculated and presented in Table 4.20.

Table 4.20: Potential for sale of natural gas in the iron & steel industry

(MCM/year)

	2000	2005	2010	2015
West Bengal	33.92	40.94	50.34	61.29
Orissa	135.90	152.92	169.69	187.43
Andhra Pradesh	14.40	18.80	23.09	29.51
TOTAL	**184.22**	**212.66**	**243.12**	**278.23**

4.4.3 Fertiliser industry

The nitrogenous fertiliser industry is highly energy intensive and one of the largest consumers of petroleum based fuels. The installed capacity of nitrogenous and phosphatic fertiliser industry in India is 8.844 million tons and 2.829 million tons of nutrients respectively.

Many different feedstocks are used e.g. coal, coke, heavy oil, naphtha, natural gas, industrial gases etc., for the production of ammonia depending on the actual availability of feedstock. (Today more than 75 percent of the total world ammonia capacity is based on natural gas.) The major part of the feedstock (74%) is consumed by the process as feed in ammonia production and the balance (26%) as fuel consumption.

The minimum theoretical energy consumption for the production of ammonia, regardless of production process, based on LHV (Lower Heating Value) of feedstock is 17 GJ/t of ammonia. The minimum theoretical requirement of natural gas (CH_4 content 81.3%) for ammonia is nearly 603 Nm^3/t of ammonia. Discussions with the Fertiliser Association of India have revealed that in practice, about 913 Nm^3 of natural gas are required to produce one ton of ammonia.

The fertiliser industry in the study region offers some potential for natural gas as the plants in West Bengal, Orissa, Andhra Pradesh and Tamil Nadu are using naphtha

and fuel oil as feedstock because there is no present source of natural gas. There is one fertiliser plant at Talcher in Orissa and another at Ramagundam in Andhra Pradesh. Table 4.21 lists the major manufacturers of fertilisers in the four states.

Table 4.21: Existing fertiliser industries in the study area

Name of the Industry	Location	Feedstock	NH_3 Capacity (tpd)
WEST BENGAL			
Hindustan Fertiliser Corporation	Durgapur	Naphtha	600
Hindustan Lever Limited	Haldia	NH_3 (sourced externally)	N/A
Durgapur Steel Plant	Durgapur	Coke oven gas (by-product)	N/A
Indian Iron & Steel Company	Burnpur	Coke oven gas (by-product)	N/A
ORISSA			
Fertiliser Corporation of India	Talcher	Coal	900
Rourkela Steel Plant	Rourkela	Coke oven gas (by-product)	N/A
Rourkela Fertiliser Plant	Rourkela	Coke oven gas & Naphtha	450
Paradeep Phosphates	Paradip	NH_3 (sourced externally)	N/A
ANDHRA PRADESH			
Coromandel Fertilisers	Vishakhapatnam	Naphtha	357
Fertiliser Corporation of India	Ramagundam	Coal	N/A
Godavari Fert. & Chemicals	Kakinada	NH_3 (sourced externally)	N/A
Nagarjuna Fertilisers & Chemicals	Kakinada	Natural Gas	900
TAMIL NADU			
EID Parry	Ennore	NH_3 (sourced externally)	N/A
Madras Fertilisers Limited	Manali	Naphtha	750
Neyveli Lignite Corporation	Neyveli	Fuel Oil	285
SPIC	Tuticorin	Naphtha	1100
Tuticorin Alkali, Chem. & Fert	Tuticorin	NH_3 (sourced externally)	N/A

Table 4.22 lists the new fertiliser plants planned in the study region. The expansions of the Nagarjuna Fertilisers plant at Kakinada and the Madras Fertilisers plant at Manali is expected to be complete by the year 2000. The new fertiliser plants at Haldia, and the IFFCO plant at Nellore are expected to materialise by 2005. As for the plants at Barddhaman and Dhenkanal, no information was available as to the expected capacity or type of feedstock.

Table 4.22: Planned fertiliser plants

Name of the Industry	Location	Feedstock	NH_3 Capacity (tpd)
WEST BENGAL			
Hindustan Fertiliser Corporation	Barddhaman	N/A	N/A
Hindustan Fertiliser Corporation	Haldia	Fuel oil	600
Paharpur Fertilisers & Chemicals	Haldia	Naphtha	1350
ORISSA			
Fertiliser Corporation of India	Dhenkanal	N/A	N/A
Oswal Chemicals[3]	Talcher	Coal	1350
ANDHRA PRADESH			
Nagarjuna Fert. & Chemicals	Kakinada	Naphtha	900
IFFCO	Nellore	Naphtha	1350
TAMIL NADU			
Madras Fertilisers Limited	Manali	Naphtha	300

4.4.3.1. Potential for natural gas sales

The Fertiliser Association of India, which is the representative body of all Indian fertiliser manufacturers, is of the opinion that any naphtha/fuel oil based fertiliser plant would, subject to price, be glad to switch to natural gas due to elimination of fuel-storage requirements and lower maintenance requirements.

For the purpose of calculating the natural gas sales potential, it has been assumed that the fertiliser plants operate for 330 days in a year and that 913 cubic meters of natural gas is required to produce one ton of ammonia.

Table 4.23 gives the expected gas requirement in the fertiliser industry in the region.

Table 4.23: Natural gas sales potential in fertiliser industry

(MCM/year)

Year	2000	2005	2010	2015
West Bengal	181	768	768	768
Orissa	136	136	136	136
Andhra Pradesh	650	1057	1057	1057
Tamil Nadu	734	734	734	734
TOTAL	**1701**	**2695**	**2695**	**2695**

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[3] Oswal Chemicals' fertiliser plant was intended to be based in Paradip and use naphtha as feedstock, but is now planning to use coal, and hence has shifted to Talcher. They intend to do captive mining of coal for the fertiliser plant.

All fertiliser plants are supplied with naphtha at a special fertiliser price which is heavily subsidised compared to market price fixed by government of naphtha. Potential exists in plants which have been designed for naphtha and fuel oil as feedstock, but major modifications are to be made in pre-reformer, gas pre-heater etc., which would entail investment that will have to be justified by cost savings from switching of feedstock to gas.

4.4.4. Cement industry

In manufacture of cement, coal is burnt (pyroprocessing) in the kilns along with limestone to produce clinker. Burning of coal provides the required heat and temperature for formation of clinker, and also the residual ash (silica) in the coal is an input to form clinker. While cement manufacture can use low grade coal, the wide variation in the quality of coal makes the task of maintaining uniform balance of limestone & silica (ash content) in the clinker very difficult, affecting the quality of the end product. Natural gas technically can substitute coal with minor modifications to the burner, with great advantage due to the following reasons:

- Use of natural gas in place of coal would obviate the need for coal handling, crushing and grinding machinery.
- The quality of coal supplied varies greatly in terms of ash content and heat value. As a result, the clinker produced does not have uniform quality. This problem would be eliminated with natural gas use as it would be easy to ensure uniform mix of limestone and silica.
- Use of natural gas gives longer life for refractory lining and reduces down time for kilns.

4.4.4.1. Potential for natural gas sales

The coal consumption in the cement industries has been taken as the basis for calculating the natural gas requirements. The production in the study region has grown at a rate of about 1.75% per year in the past, and it is assumed that the same trend would continue in the future also. The equivalence factor is 410 MCM of gas for a million ton of coal. The potential for gas sale to the cement industries is given in Table 4.24.

Table 4.24: Potential for sale of natural gas in the cement industries

(MCM/year)

	2000	2005	2010	2015
West Bengal	2	2	3	3
Orissa	112	122	133	145
Andhra Pradesh	853	931	1017	1107
Tamil Nadu	513	562	611	668
TOTAL	**1480**	**1617**	**1764**	**1923**

4.4.5 Petrochemicals

The potential in related major industries was also assessed and a partial list of these industries including, Heavy Chemicals, Insecticides, Petrochemicals, Metal extraction is given in Table 4.25.

Table 4.25: Petrochemical industries

Name of the Industry	Type	Location/State	Capacity (MMTPA)
SPIC	Petro Chemical	Madras, Tamil Nadu	5.60 million - Urea 0.38 million - Ammonia 0.77 million - LPG
UB Petro Products Ltd	Petro Products	Madras, Tamil Nadu	1200 PO 8250 PG 8000 PE
Tamil Nadu Petro Products Ltd	Petro Products	Madras, Tamil Nadu	85000 Linear Alkalis 10000 ECH
Manali Petro Chemicals Ltd	Petro Chemicals	Madras, Tamil Nadu	12000 PO 6250 PG 6000 Polyoes
Dalmia Magnesite Corporation	Magnesite	Salem, Tamil Nadu	72000 Dead Burn Magnesite

Most of these industries are using fuels like LPG, FO, LSHS and petroleum coke in boilers, furnaces, dryers etc.

The Madras Refinery Limited (MRL) and SPIC are planning a joint venture petrochemical unit (Arochem Industries). The feedstock will be naphtha from the refinery and hence the possibility of using natural gas may be ruled out.

There are no other major petrochemical industries planned in the region at present, but one is being constructed at Haldia in West Bengal, details of which are given in Table 4.26. Naphtha is the proposed feedstock for the Haldia petrochemical plant.

Table 4.26: Proposed product mix for Haldia Petrochemicals

Product	Capacity (MMT/year)
Ethylene	0.30
Propylene	0.15
Polypropylene	0.10
LDPE	0.08
Mixed C_4s	0.09
Benzene	0.06
Butadiene	0.06
Pyrolysis Gasoline	0.08
HDPE	0.20
Total	**1.12**

Natural gas sales potential in Haldia plant is estimated as being limited as the proposed product mix would undergo a change if natural gas were to be used instead of naphtha[4].

The overall potential in the petrochemical industry in the four states considered is estimated as being small.

4.4.6 Domestic

The urban domestic sector consumes a large quantity of liquefied petroleum gas (LPG) which could be replaced by natural gas. Though setting up the distribution network would be an expensive affair, once in place, it would cater to a captive consumer class. The consumers would welcome the opportunity to have piped supply of gas for cooking instead of having to rely on the often erratic supply of LPG cylinders.

4.4.6.1. Potential for natural gas sales

Using an equivalence factor of 1.233 cubic metre of natural gas for every kilogram of LPG, the potential demand for natural gas is calculated and given in Table 4.27. While a substantial potential demand exists for natural gas in the domestic sector for the study region as a whole, it would only be feasible to tap the demands in the major cities which fall along a natural gas pipeline.

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[4] Benzene and butadiene cannot be produced when using natural gas as feedstock.

Table 4.27: Potential for sale of natural gas in the domestic sector

(MCM/year)

	2000	2005	2010	2015
West Bengal	418	607	751	927
Orissa	81	118	168	247
Andhra Pradesh	613	1036	1340	1408
Tamil Nadu	755	879	994	1157
TOTAL	**1867**	**2640**	**3253**	**3739**

4.5. CONCLUSION

The total natural gas sales potential in the four states is summarised in Table 4.28.

Table 4.28: Natural gas sales potential in the four states

(MCM/year)

	2000	2005	2010	2015
WEST BENGAL				
Power	445	880	991	2245
Iron & Steel	34	41	50	61
Fertiliser	181	768	768	768
Cement	2	2	3	3
Domestic	418	607	751	927
Total	**1080**	**2298**	**2563**	**4004**
ORISSA				
Power	95	1597	3843	6898
Iron & Steel	136	153	170	187
Fertiliser	136	136	136	136
Cement	112	122	133	145
Domestic	81	118	168	247
Total	**560**	**2126**	**4450**	**7613**
ANDHRA PRADESH				
Power	846	3441	7970	15776
Iron & Steel	14	19	23	30
Fertiliser	650	1057	1057	1057
Cement	853	931	1017	1107
Domestic	613	1036	1340	1408
Total	**2976**	**6484**	**11407**	**19378**
TAMIL NADU				
Power	3044	9239	20364	29515
Iron & Steel	0	0	0	0
Fertiliser	734	734	734	734
Cement	513	562	611	668
Domestic	755	879	994	1157
Total	**5046**	**11414**	**22703**	**32074**
GRAND TOTAL	***9662***	***22322***	***41123***	***63069***

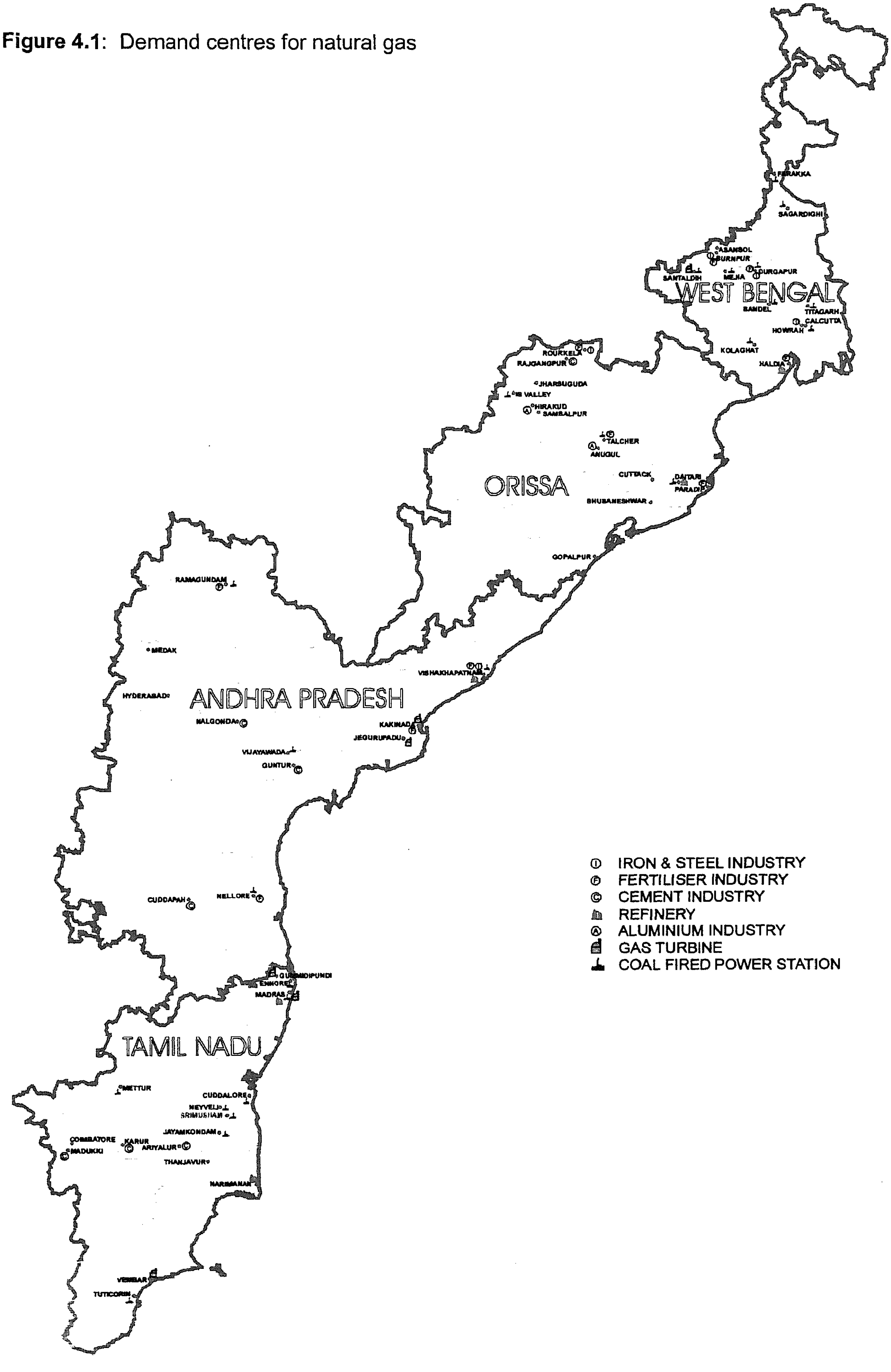


Figure 4.1: Demand centres for natural gas

CHAPTER 5
IMPUTED VALUE OF NATURAL GAS

5.1. IMPUTED VALUE FOR NATURAL GAS IN THE POWER SECTOR

5.1.1. Definition

Imputed value or replacement value for natural gas is defined as the value of the gas at which the cost of a unit output in a gas based plant is equal to the cost of unit output in a plant based on alternative fuel/feedstock. When gas is priced at its imputed value, the customer would be indifferent to choices (in terms of cost implications) between gas and the substitute fuel, presently in use.

In the present study, the imputed value for gas for power generation is computed in comparison to substitute fuels (coal, naphtha and fuel oil) for representative sites in West Bengal (Calcutta), Orissa (Paradip), Andhra Pradesh (Vishakhapatnam) and Tamil Nadu (Madras). They are important urban centres and ports, and are geographically well spread out.

5.1.2. Technical and financial parameters

The capital costs of the various types of power plants have been provided by General Electric, Asea Brown Boveri and Bharat Heavy Electricals Limited, all reputed equipment manufacturers. Included in the capital cost are costs for project development, land, contingencies and initial working capital, besides the engineering, procurement and construction (EPC) costs. In the case of coal based technologies, the cost for ash disposal is also taken into account.

Table 5.1 lists the various technical and financial parameters of gas based (combined cycle) plants considered for arriving at the imputed value.

Table 5.2 lists the various technical and financial parameters of conventional coal based plants considered for arriving at the imputed value, while Table 5.3 does the same for integrated gassification coal combustion (IGCC) combined cycle plants.

While the plant load factor (PLF) has been taken as 68.5%, and the heat rate for a conventional fired plant as 2500 kcal/kWh, for the purpose of arriving at the imputed values of natural gas, there is a proposal before the Central Electricity Authority of India (CEA) to revise the base PLF to 75% and lower the normative heat rate for a coal fired power station to 2040-2120 kcal/kWh, which would have the effect of lowering the imputed value for natural gas relative to conventional coal stations.

Table 5.1: Technical and financial parameters for gas based (combined cycle) plants

S. No.	Technical Parameters	Units	Values
1.	Plant load factor	%	68.50
2.	Auxiliary consumption	%	3.00
3.	Life of plant	Years	20.00
4.	Calorific value	Kcal/Kg	8760.00
5.	Heat rate	Kcal/kWh	1625.00
6	Fixed operating cost	Rs./kWh	0.11

S. No.	Financial Parameters	Units	Values
1.	Discount rate	%	12
2.	Capital cost per MW	Rs. million	24.5
3.	Investment period	Years	3

Table 5.2: Technical and financial parameters for conventional coal based plants

S. No.	Technical Parameters	Units	Values
1.	Plant load factor	%	68.50
2.	Auxiliary consumption	%	9.50
3.	Life of plant	Years	25.00
4.	Calorific value (Indigenous)	Kcal/Kg	4200.00
5.	Calorific value (Imported)	Kcal/Kg	6250.00
6.	Heat rate	Kcal/kWh	2500.00
7.	Fixed operating cost (Indigenous)	Rs./kWh	0.16
8.	Fixed operating cost (Imported)	Rs./kWh	0.18

			Values	
S.No.	Financial Parameters	Units	Imported	Indigenous
1.	Discount rate	%	12	12
2.	Capital cost per MW	Rs. million	37.86	35.97
3.	Investment period	Years	4	4

The auxiliary consumption in an IGCC plant is high due to the presence of an oxygen blown gassifier, which uses a cryogenic process for the production of oxygen. The capital cost of an IGCC plant using indigenous coal is higher than that for an imported plant as the generator size for Indian coal is limited to 110 MW because of the problem of high ash content, while imported coals, which are low in ash, can support higher capacity ratings.

Table 5.4 lists various technical and financial parameters for naphtha and fuel oil (combined cycle) based plants considered for arriving at the imputed value.

Table 5.3: Technical and financial parameters for IGCC (combined cycle) plants

S. No.	Technical Parameters	Units	Values
1.	Plant load factor	%	68.50
2.	Auxiliary consumption	%	20.00
3.	Life of plant	Years	20.00
4.	Calorific value (Indigenous)	Kcal/Kg	4200.00
5.	Calorific value (Imported)	Kcal/Kg	6250.00
6.	Gross Heat rate	Kcal/kWh	1625.00
7.	Fixed operating cost (Indigenous)	Rs./kWh	0.22
8.	Fixed operating cost (Imported)	Rs./kWh	0.17

			Values	
S.No.	Financial Parameters	Units	Imported	Indigenous
1.	Discount rate	%	12	12
2.	Capital cost per MW	Rs. million	47.3	58.2
3.	Investment period	Years	4	4

Table 5.4: Technical and financial parameters for naphtha and fuel oil (combined cycle) based plants

S. No.	Technical Parameters	Units	Naphtha	Fuel Oil
1.	Plant load factor	%	68.50	68.50
2.	Auxiliary consumption	%	3.00	3.00
3.	Life of plant	Years	20.00	15.00
4.	Calorific value	Kcal/Kg	10560.00	10440.00
5.	Heat rate	Kcal/kWh	1625.00	1767.00
6.	Fixed operating cost	Rs./kWh	0.11	0.11

S. No.	Financial Parameters	Units	Naphtha	Fuel Oil
1.	Discount rate	%	12	12
2.	Capital cost per MW	Rs. million	24.5	25.11
3.	Investment period	Years	3	3

The capital cost of a fuel oil (grade 2) fired combined cycle gas turbine has been taken higher than that for naphtha or natural gas fired as it includes the cost of a fuel treatment plant to reduce the sulphur content of fuel oil. The reduction in sulphur content can be achieved by blending the fuel oil with "cutter stock" which has a lower sulphur level. The heavy metals present in fuel oil reduce the life of the plant to 15 years as opposed to 20 years for a naphtha or gas fired turbine.

5.1.3. Fuel cost

5.1.3.1. Indigenous coal

The collieries selected are Raniganj in West Bengal, Talcher in Orissa and Godavari (Singareni) in Andhra Pradesh. 'F' grade Coal is considered at a pithead price (inclusive of royalty, sales tax etc.) of Rs 445.78/ton. The landed cost at the four selected locations is arrived at by adding freight to the pithead cost and is given in Table 5.5.

5.1.3.2. Imported coal

Superior grade steam coal from Australia/S. Africa is considered. The c.i.f. price is US $ 55/t (Rs 1925/ton). To arrive at the delivered price at the Indian ports, the cost of port handling is added to the c.i.f. price. Finally, the landed price (Table 5.5) is obtained by adding rail tariffs to the c.i.f. price. Wagon loading and unloading is ignored because of its small charge value. The customs duty on coal is 10%. Imported coal for Calcutta is unloaded at Haldia as Calcutta port does not handle coal.

5.1.3.3. Indigenous naphtha and fuel oil

Indigenous naphtha and fuel oil is assumed to be transported to the sites by rail from the refineries at Haldia, Vishakhapatnam and Madras. The ex-storage price of indigenous naphtha is Rs. 6683/ton while that for fuel oil is Rs. 5896/ton. Sales tax, excise duty and transportation cost are added to the ex-storage price to arrive at the landed cost at the site (Table 5.5).

5.1.3.4. Imported naphtha and fuel oil

The c.i.f. price of imported Naphtha is Rs. 5985/ton ($ 171/ton), inclusive of a Rs 167/ton marketing margin, to which is added rail freight, sales tax, countervailing duty, etc. to arrive at the landed cost (Table 5.5). (The customs duty on naphtha is nil and hence not included.) The c.i.f. price for imported fuel oil is taken as Rs. 3443/ton ($ 98/ton), inclusive of a marketing margin of Rs 129/ton. All the four cities have ports which handle petroleum products.

The rate of exchange is taken as 1 US $ = Rs. 35.00.

Table 5.5: Landed cost of fuels at selected locations

(Rs/ton)

Fuel	Calcutta	Paradip	Vishakhapatnam	Madras
Coal				
Indigenous	599	587	783	1379
Imported	2434	2343	2343	2343
Naphtha				
Indigenous	7862	8297	7686	7686
Imported	6883	6883	6883	6883
Fuel Oil				
Indigenous	6956	7392	6780	6780
Imported	4545	4545	4545	4545

5.1.3.5. Calculations

Based on the above assumptions, the replacement values of natural gas for power generation, as a substitute for coal, naphtha or fuel oil, at selected locations are estimated.

The generation costs and imputed values calculated are given in Tables 5.6 and 5.7 respectively while the detailed calculations are given in Appendix 5.1, 5.2, 5.3 and 5.4 for conventional coal, IGCC coal, naphtha and fuel oil respectively.

The generation cost varies from a low of 4.29 ¢/kWh in the case of a power station using indigenous coal in a conventional station located at Paradip, to a high of 8.07 ¢/kWh for a station based on indigenous coal in an IGCC plant located at Madras.

Table 5.6: Cost of power generation with different fuels

(US cents/kWh)

Source	Indigenous				Imported			
Fuel	Conv. Coal	IGCC Coal	Naphtha	Fuel Oil	Conv. Coal	IGCC Coal	Naphtha	Fuel Oil
Calcutta	4.31	6.99	5.44	5.58	6.08	6.70	5.02	4.45
Paradip	4.29	6.98	5.63	5.79	5.99	6.64	5.02	4.45
Vishakhapatnam	4.59	7.15	5.37	5.50	5.99	6.64	5.02	4.45
Madras	5.51	8.07	5.37	5.50	5.99	6.64	5.02	4.45

The imputed values of natural gas vary from $ 3.26/MMBtu in the case of indigenous coal in a conventional plant for Durgapur or Rourkela, to $ 8.05 for an IGCC plant based on indigenous coal in Patna. Since indigenous coal is the primary fuel source in the region, natural gas will not be competitive if priced above $ 3.25/MMBtu for the power sector.

Table 5.7: Imputed values of natural gas in power sector

(US $/MMBtu)

Source	**Indigenous**				**Imported**			
Fuel	**Conv. Coal**	**IGCC Coal**	**Naphtha**	**Fuel Oil**	**Conv. Coal**	**IGCC Coal**	**Naphtha**	**Fuel Oil**
Calcutta	3.56	7.85	5.37	5.60	6.40	7.38	4.70	3.78
Paradip	3.53	7.84	5.67	5.92	6.25	7.30	4.70	3.78
Vishakhapatnam	4.01	8.11	5.25	5.46	6.25	7.30	4.70	3.78
Madras	5.48	9.59	5.25	5.46	6.25	7.30	4.70	3.78

5.2. IMPUTED VALUE FOR NATURAL GAS IN THE INDUSTRIAL SECTOR

5.2.1. Iron & steel industries

The primary consumers of the fuel oil sought to be replaced by natural gas in this sector are re-rolling mills which utilise the fuel oil to heat ingots for hot rolling. Assuming the efficiencies of combustion of fuel oil and natural gas to be the same, the imputed value of natural gas against fuel oil in the iron & steel sector is derived as follows:

$$\text{Imputed value of natural gas} = \frac{\text{Rs}\,5.896\,/\,\text{litre} * 1.071\,\text{litre}\,/\,\text{kg} * 251996\,\text{kcal}\,/\,\text{MMBtu}}{10440\,\text{kcal}\,/\,\text{kg} * \text{Rs}\,35\,/\,\$}$$

Imputed value of natural gas in iron & steel = $ 4.35/MMBtu

5.2.2. Fertiliser industries

Nitrogenous fertiliser industries produce urea from ammonia. To make ammonia, various types of feedstock, such as coal, coke, naphtha, fuel oil, natural gas, etc. are used. Of these, naphtha and fuel oil have been considered to be suitable for replacement with natural gas, and hence the imputed values have been worked out with respect to naphtha and fuel oil.

As per the discussions held with the Fertiliser Association of India, 0.99 tons of fuel oil and 0.83 tons of naphtha are needed to produce one ton of ammonia. The natural gas requirement is about 913 Nm^3 for the same, taking the calorific value to be 8760 kcal/Nm^3.

Table 5.8: Imputed value calculations in fertiliser industry

Particulars	Naphtha	Fuel Oil
Quantity required to produce one ton of ammonia	0.83 tons	0.99 tons
Price	Rs 4840/ton	Rs 3656/kilo litre
Equivalent price per ton of ammonia (Rs/ton of NH_3)	Rs 4017	Rs 3876
Calorific value	10560 kcal/kg	10440 kcal/kg
Equivalent energy required (MMBtu/ton of NH_3)	41 MMBtu	35 MMBtu
Imputed value of natural gas ($/MMBtu)	**$ 3.59/MMBtu**	**$ 3.46/MMBtu**

A price of around $ 3.50/MMBtu for natural gas should be suitable for the fertiliser industry.

5.2.3. Cement industries

Grade ‘D’ coal having a calorific value of 6000 kcal/kg is used in the cement industries. The major clusters of cement industries are located in Andhra Pradesh and Tamil Nadu, and the average lead for coal transportation in these two states is about 600 km.

Taking only the fuel cost into consideration, and assuming the efficiencies of combustion for natural gas and coal in the cement industry to be the same, the imputed value for natural gas in the cement industry works out to be $ 1.74/MMBtu.

5.3. IMPUTED VALUE FOR NATURAL GAS IN THE DOMESTIC SECTOR

The liquefied petroleum gas supplied to domestic consumers has a calorific value of 10800 kcal/kg and is priced at Rs 6902/ton. Based on this, the imputed value for natural gas in the domestic sector is $ 4.60/MMBtu. Currently, subsidy on LPG for domestic use is about Rs 4945/ton, but is expected to disappear in the future. The imputed value would then be $ 7.90/MMBtu.

CHAPTER 6
GAS AND PETROLEUM PRODUCTS DISTRIBUTION NETWORK

6.1. GAS PIPELINES

6.1.1. Existing distribution network

The existing major gas pipeline in India is the 1800 Km Hazira-Bijaipur-Jagdishpur (HBJ) gas pipeline system which carries 20 MMSCMD gas from the western coast of India to the central and northern parts of the country. The HBJ system is owned and operated by the Gas Authority of India Limited (GAIL). Apart from this, GAIL has smaller pipeline networks supplying gas to industries from offshore/onshore gas fields in the western, north-eastern and southern parts of the country. These pipeline networks are smaller and vary in size from 4 Km to 80-90 Km in length; and 10 cm to 45-60 cm in diameter and account for the transmission and distribution of the balance gas sales today.

6.1.2. Projects commissioned recently

In the recent past GAIL has established following infrastructure for the supply of gas to major new consumers:

- Spur line to Indian Oil Company (IOC), Mathura completed and gas supply to the refinery commenced from December, 1996.
- Pipeline to M/s GVK's power plant at Jegurupadu was completed in April, 1996 and to the Spectrum power plant in July, 1996.
- Six pipelines were completed during the past year for supply of gas to consumers from isolated gasfields in Gujarat region.

6.1.3. Future plans

GAIL plans to construct an 1,820 Km long gas pipeline for LPG of 35-40 cm diameter from Kandla, Okha/Sikka to Piyala. The project is expected to cost $ 495 million and would be completed in 36 months after government approval.

The existing and proposed gas pipeline distribution network are shown in Figure 6.1.

6.2. CRUDE OIL DISTRIBUTION NETWORK

6.2.1. Existing pipelines

Major crude pipelines exist between the following locations:

- From Vadinar in Gujarat to Mathura in Uttar Pradesh.

- From Bombay High and Heera oil fields to Bombay.
- From Digboi in Assam to Barauni in Bihar.

6.2.2. Pipelines proposed and under construction

The major pipelines under construction are, from Barauni in Uttar Pradesh to Haldia in West Bengal and a spur from Chaksu in Rajasthan, through the Vadinar-Mathura pipeline, to Panipat in Haryana. Among the proposed pipelines are, from Vadinar to Sultanpur in Uttar Pradesh through Bina in Madhya Pradesh, and from Vadinar to Bhatinda in Punjab through Jaipur in Rajasthan.

The existing and proposed pipeline network for crude oil are shown in Figure 6.2.

6.3. PETROLEUM PRODUCTS DISTRIBUTION NETWORK

6.3.1. Existing pipelines

The major existing petroleum products distribution pipelines are as follows:

- Kandla in Gujarat to Panipat in Haryana, from where branches have been constructed to Bhatinda and Jalandhar in Punjab.
- Mathura in Uttar Pradesh to Panipat in Haryana through Delhi.
- Haldia in West Bengal to Kanpur in Uttar Pradesh through Patna and Allahabad.
- Guwahati in Assam to Siliguri in West Bengal through Bongaingaon.

6.3.2. Pipelines proposed and under construction

The pipelines under construction are, from Vijayawada to Vishakhapatnam in Andhra Pradesh and from Bombay to Manmad in Maharashtra. The proposed pipelines are:

- Bina in Madhya Pradesh to Mathura in Uttar Pradesh through Kanpur.
- Paradip in Orrisa to Ranchi in Bihar through Rourkela and Cuttack.
- Cochin in Kerala to Kaur in Tamil Nadu through Coimbatore.
- From Mangalore to Bangalore in Karnataka.

The existing and proposed pipeline network for petroleum products are shown in Figure 6.3

Figure 6.1: Existing and proposed gas distribution network

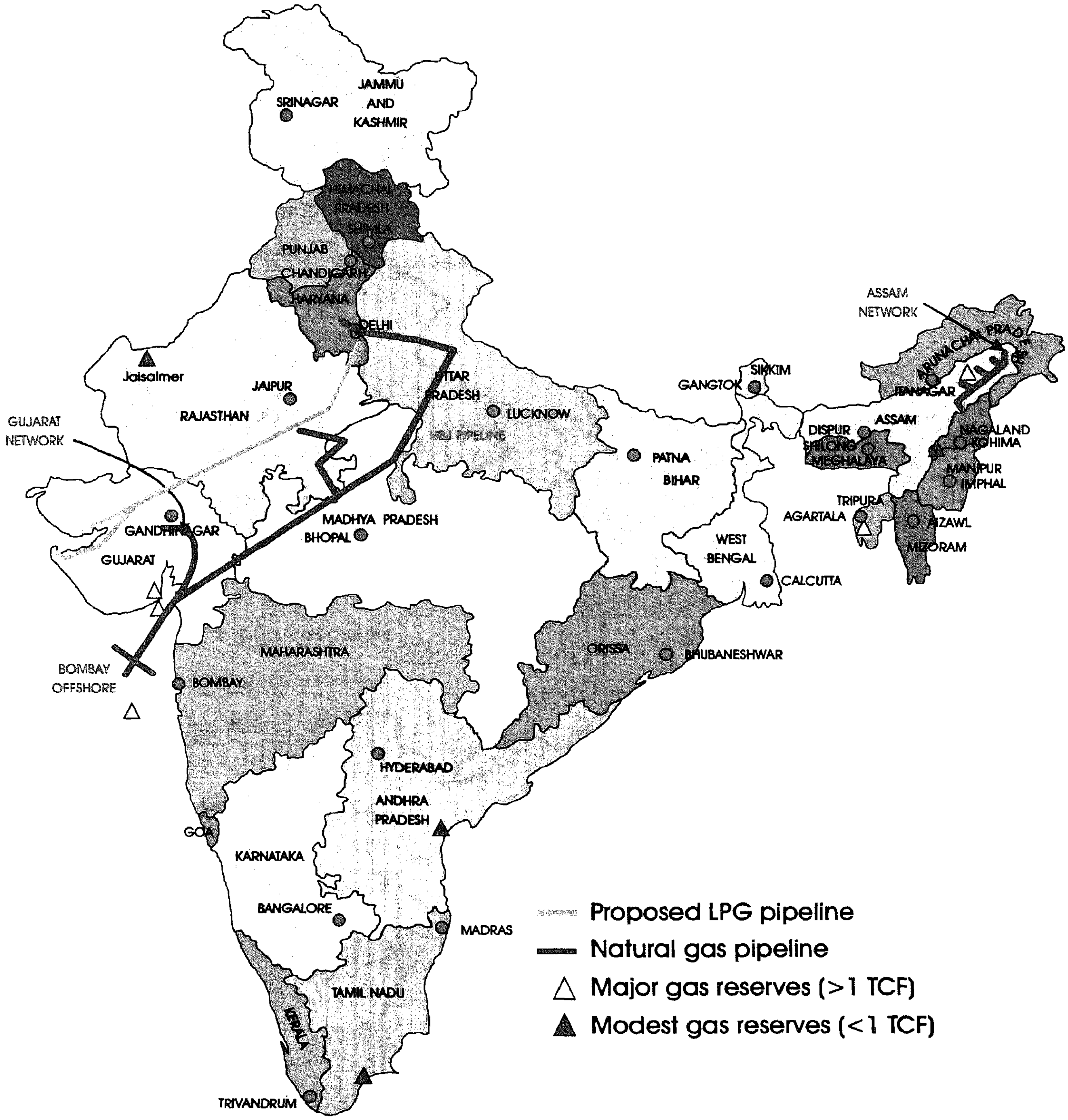


Figure 6.2: Existing and proposed crude oil distribution network

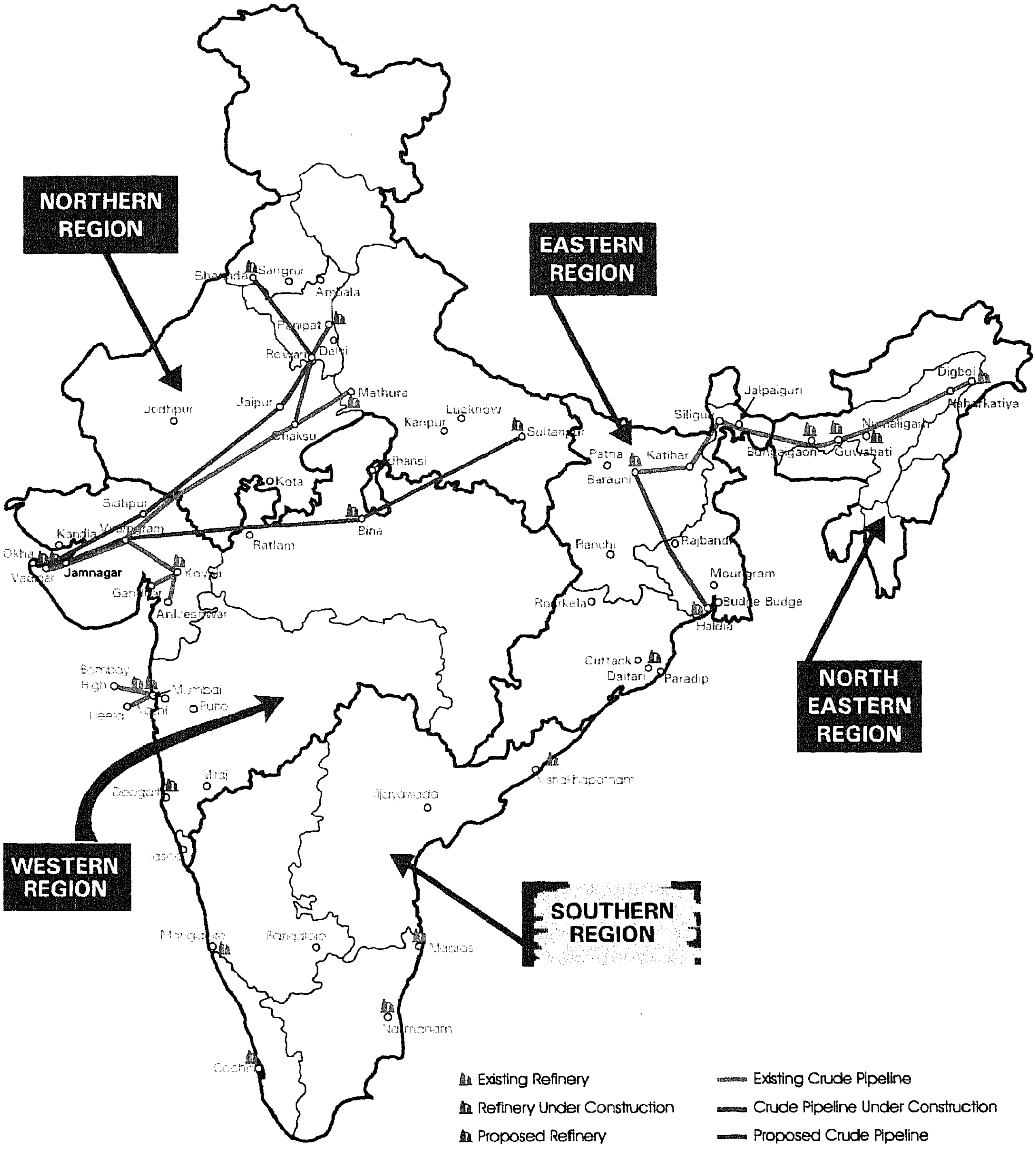
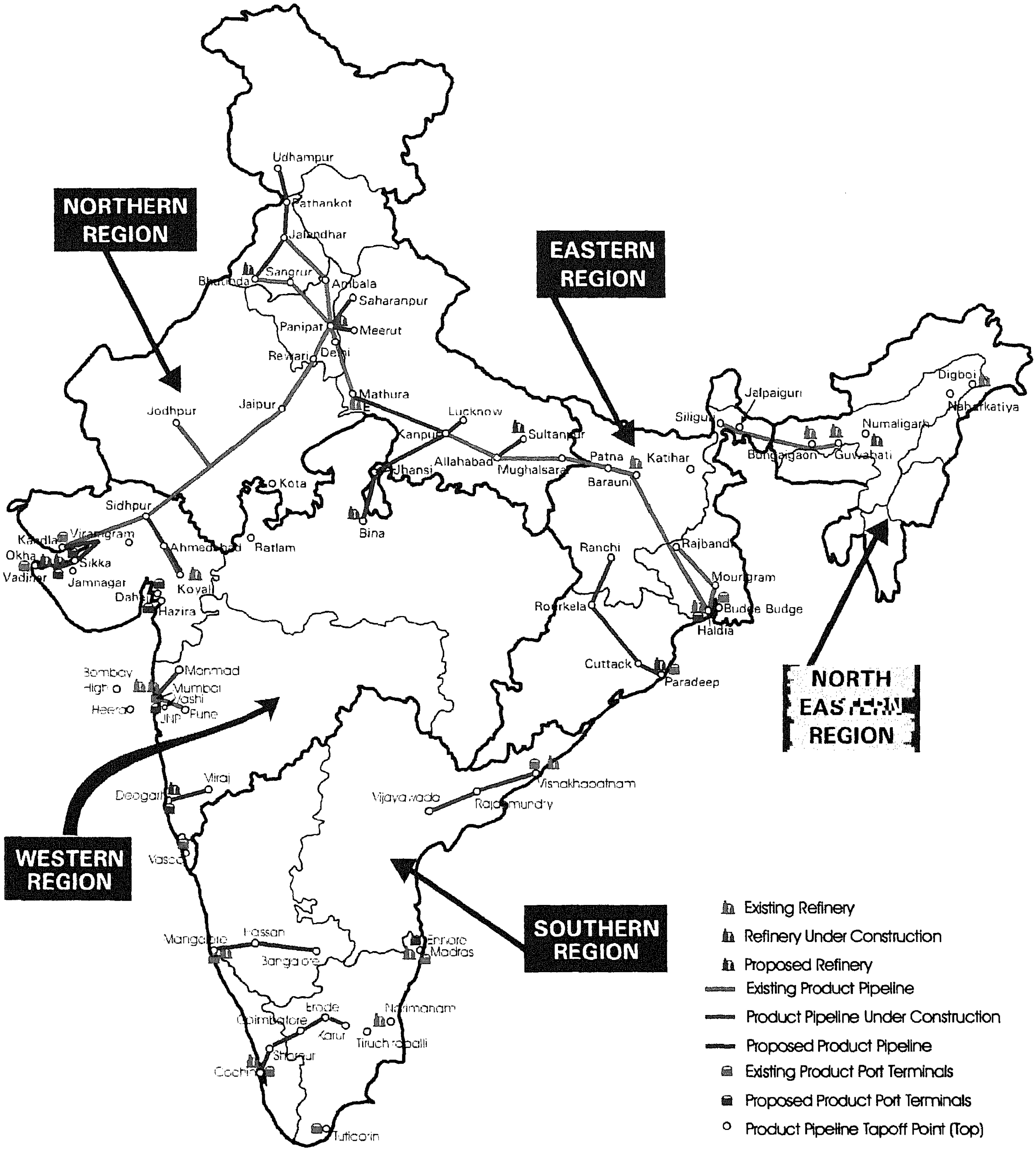


Figure 6.3: Existing and proposed petroleum products distribution network

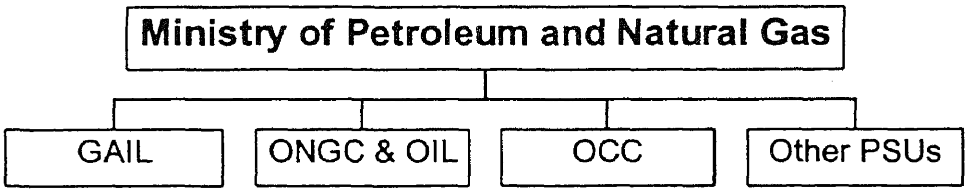


CHAPTER 7
REVIEW OF ROLE OF ONGC, OIL AND GAIL

7.1. INDIA'S HYDROCARBON SECTOR

The Indian hydrocarbon industry is dominated by public sector undertakings which function under the administrative control of Ministry of Petroleum and Natural Gas (MOP&NG) as shown in Figure 7.1. The Ministry is responsible for exploration and production of crude oil and natural gas as well as for refining, distribution and marketing of petroleum products and natural gas. Its role also extends to imports and exports of crude oil and petroleum products. Such a set up took shape as a result of the government's view of the strategic importance of the hydrocarbon industry which warranted state control. In 1975 Oil Coordination Committee (OCC) was set up to coordinate various activities such as planning for imports and exports of petroleum products and crude oil within the country. OCC prepares short-term estimates of supply, demand and imports; formulates new projects; maintains the oil pool accounts and monitors the progress of ongoing projects and the performance of oil industry in general to achieve maximum utilisation of their refining capacity.

Figure 7.1: Organisational chart of the MOP&NG



The tasks of the ministry are exercised through various Public Sector Undertakings (PSUs) which include Oil and Natural Gas Corporation Limited (ONGC), Oil India Limited (OIL), Gas Authority of India Limited (GAIL), Indian Oil Corporation (IOC) among others. They are listed below according to their roles :

Exploration and Production

- Oil and Natural Gas Corporation Limited (ONGC).
- Oil India Limited (OIL).

Transportation and Marketing of Natural Gas

- Gas Authority of India Limited (GAIL).

Refining and/or Marketing

- Indian Oil Corporation Limited (IOC).
- Hindustan Petroleum Corporation Limited (HPCL).
- Bharat Petroleum Corporation Limited (BPCL).
- Madras Refineries Limited (MRL).
- Cochin Refineries Limited (CRL).
- Bongaigaon Refinery and Petrochemicals Limited (BRPL).
- IBP Co Limited (IBP).
- Numaligarh Refinery Limited (NRL)

Other Organisations under the Ministry

- Engineers India Limited (EIL).
- Lubrizol India Limited (LIL).
- Balmer Lawrie Limited.

The Indian oil and gas industry is going through a period of reform, and in the recent past, there has been an increasing trend towards collaboration with private sector: both national as well as international. The inability of the domestic Exploration and Production companies to satisfy the domestic demand has created a sense of urgency to deregulate. The essence of restructuring the hydrocarbon industry is to introduce and foster the conditions of a competitive market so as to stimulate improvements in productivity and maximise the consumer surplus.

Substantial changes have taken place in other countries of the world in the development and application of technology in various segments of the hydrocarbon industry. There is evidence that the technology gap in certain parts of India's hydrocarbon industry in relation to state-of-the-art global practice has actually widened in the recent past. The restructuring exercise is meant to ensure that not only the best technology available in other parts of the world is quickly adopted and introduced in India, but also that capabilities within the country are built effectively to ensure smooth adaptation and further development of these technologies for the benefit of Indian organisations, so that the Indian hydrocarbon industry becomes capable of an international presence in the global scenario.

7.2. OIL AND NATURAL GAS CORPORATION LIMITED (ONGC)

ONGC was established as Oil and Natural Gas Commission for the development of petroleum resources and the production and sale of petroleum and petroleum products produced by it and for matters connected therewith. Pursuant to the decision of the Government of India (GOI) to convert Oil and Natural Gas Commission into a public limited company, "Oil and Natural Gas Corporation Ltd." was incorporated under the Companies Act, 1956 on June 23, 1993.

ONGC is the premier gas exploration and production company in the country, accounting for 90% of the total domestic production. The company's revenue are primarily derived from the sale of crude oil, natural gas, LPG, ethane-propane fractions and NGL. Starting with almost negligible reserves, little financial resources and no expertise thirty six years ago, today ONGC not only ranks 13th among non-US oil companies with a reserve base of over 5,350 MMT of oil and oil equivalent of gas (OEG) but also has built up a strong technical expertise in all facets of upstream hydrocarbon industry. ONGC has established a number of R&D institutes and has a firm commitment to the safety and environment standards.

During the past few years ONGC has launched a new phase of development through commercialisation, strategic alliances and diversification.

In view of the steadily rising demand for crude and petroleum products, several measures have been undertaken by the GOI to attract foreign and indigenous private investors in the private sector and also to reform the public sector enterprises. ONGC has strived to consolidate its strength as a low cost oil and gas producer with a well established production infrastructure, excellent reserves position as well as dedicated and talented manpower base.

7.2.1. ONGC's performance at a glance

Though ONGC suffered declining production in all the major oil fields during the past one year, the reasons for each were different. The drop in Bombay High's production was due to a steeper decline ratio of fields, and the fact that production in most of them had peaked. Though the declining phase began in 1991-92, the Neelam oil fields, which went on stream in 1994-95 masked the decline. Moreover Neelam, which was expected to contribute around 3.5 MMT per year suffered a massive decline in production, due to the reduced pressure, from second year and is now producing at half the expected rate.

Figure 7.2: Physical Production Parameters of ONGC

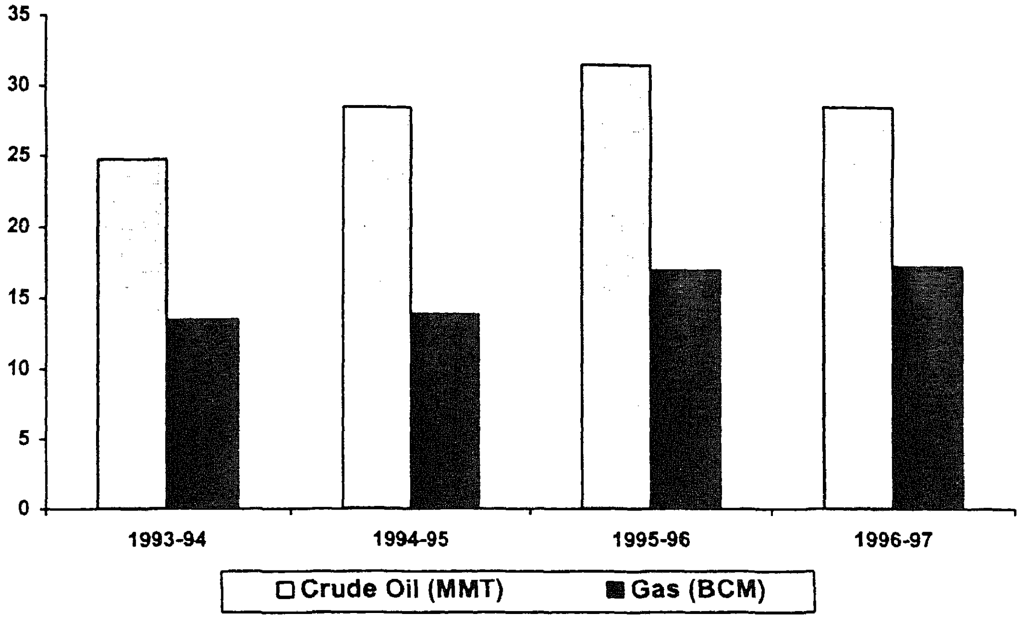


Table 7.1: Financial Performance of ONGC

Description	Unit	1993-94	1994-95	1995-96	1996-97
Revenue	Million $	2,891.66	3,337.46	3,683.42	3,521.14
Profit after Tax	Million $	455.71	670.00	525.42	536.28

7.2.2. Exploration and production(E&P)

ONGC in its quest to augment its production has undertaken and has further plans to undertake projects involving sizeable capital outlays and long duration. Project implementation has been given the highest priority and the past few years have witnessed significant construction activities in respect of various projects in Western offshore and onshore projects at Hazira and Gandhar. The expansion plans have however been constrained due to the cash crunch being faced by the oil majors due to the oil pool account deficit.

ONGC has proven oil and oil equivalent reserves exceeding 1,300 MMT with prognosticated reserves more than three times its proven reserves. Its reserve to production ratio is healthy 30 years. Though ONGC's reserve include only geological reserves, it ignores the technical and economic possibility of exploiting these reserves based on current technology and prices. Moreover, only 25% of the total area containing probable oil reserves has been explored. Given the falling production from major fields, a high reserve base with almost 75% of the area unexplored indicates inadequate investment in exploration and production.

In absolute terms India figured in the top five countries in the exploration activity in 1995-96, but 2D surveys formed a major part of the total surveys being carried out. Further, as a cost cutting measure, wild cat drilling was limited to only 357 wells. Recent exploration efforts have focused on deeper formations in the Kutch--Saurashtra area and at Bombay High. Of the 26 sedimentary basins in India that are considered to be oil bearing, only six have been explored so far. The government needs to keep petroleum product prices low, and has starved ONGC of funds for additional exploration and development. For well over a decade, its spending in this area has stayed at steady 15% of total revenues. ONGC has had no major finds since the late eighties, and had to fall back on existing discoveries to meet production targets.

E&P companies throughout the world spend sizeable sums to maintain and increase their reserve and production base. While timing forms a critical part of the exercise, ONGC, like other PSUs, is hampered by a host of clearances required to be obtained for any major project. Moreover, large investments required to convert possible reserves to proven reserves would not materialise if the E&P sector is reimbursed at very low prices. A monopolistic position in the domestic E&P sector has also contributed to this factor. The working of PSUs is further constrained by the system which dampens the initiative to be innovative and take risks. The employee remuneration system is also not conducive for promoting higher performance levels.

The Governments failure to increase the prices of petroleum products compounded with its inability to cut rising costs and hardening of the international crude prices could lead to the ballooning of the oil pool account deficit. The cash crunch could not have come at a worst time since most petroleum companies have lined up huge investments in modernisation and capacity enhancement. It is likely to have serious implications for the expansion plans and the government's disinvestment program of the ONGC's equity. Resource and autonomy being the major constraints for ONGC it can be argued that the current years production shortfall would itself accelerate steps to align the domestic prices with the international ones. This would serve to speed up deregulation in the upstream oil sector.

The disinvestment program of ONGC was initiated in the middle of 1993 and the government offloaded 2% of its equity to mutual funds and financial institutions. An additional 2% was offered as equity to its employees. The further disinvestment

would depend on the government's view of the importance of the industry and correcting the various ailments affecting it.

In the current liberalised economic scenario it has become imperative for ONGC to look for new opportunities of globalisation and collaborative development. With the faster growth of Indian economy, the demand for energy is expected to grow at much faster rate. Indian hydrocarbon industry, therefore, will have the arduous task to increase the domestic supply of hydrocarbons in consonance with the rising demand. In order to bridge the gap, hydrocarbon resources have to be scouted beyond the boundary limits of the country. ONGC has been carefully evaluating the options of acquisition of acreage as well as reserves abroad. ONGC Videsh Ltd. (OVL), a wholly owned subsidiary of ONGC, currently has a Production Sharing Contract jointly with British Petroleum and Statoil, in Vietnam, where 2 TCF gas reserves have been discovered. OVL has also taken stakes in Production Sharing Contracts in Tunisia and Egypt. An International Cooperation Group has been established to actively pursue several Joint Venture proposals both within and outside the country.

Though the bureaucratic delays and the resource crunch may explain why ONGC has been unable to set up any major new oil wells, it certainly does not justify the mismanagement of existing ones. For example, it is argued that the ONGC made serious errors while injecting water into the oil reservoir--done to maintain underground pressure--at Bombay High. Further it is also charged with over exploiting its wells and not carrying out adequate repairs. Though ONGC has achieved significant goals in the past, it needs to adjust itself according to the changing economic and market environment to maintain its dominant position.

7.3. OIL INDIA LIMITED (OIL)

OIL was established in 1886 as a private venture and was nationalised in 1981. It is engaged in exploration and production of crude oil and natural gas from its Petroleum Exploration License (PEL) areas and Mining Lease areas which include Assam, Arunachal Pradesh, Orrisa, Gujarat, Andaman, Bihar, Uttar Pradesh and Rajasthan. It is also involved in production of LPG at its plant located at Duliajan in Assam and in transportation of crude oil (OIL+ONGC crude) to designated refineries in Assam and Bihar. OIL is also selling natural gas to Assam State Electricity Board (ASEB), Indian Oil Company, and nearby tea gardens.

OIL produced 2.15 MMT of crude oil during the year 1996-97 (up to Dec. 1996). Total natural gas sales and the LPG production during the period were 709.00 MCM and 38,279 tons respectively and the total revenue was $332.00 million. Significant achievements of the year include: starting supply of natural gas from its gas-fields in the Jaisalmer basin in Western Rajasthan to Rajasthan State Electricity Board (RSEB) for power generation at Ramagarh through GAIL's pipeline and completion of first phase of exploratory drilling in the Saurashtra Offshore area.

OIL has put its proposed public issue on the hold, taking a cue from the Disinvestment Commission, that has advised the government not to offload shares of oil majors till the Administered Price Mechanism (APM) is dismantled. It has decided to raise its projected resources shortfall of $ 71.43 million through the debt route.

7.4. SUMMARY

Both ONGC and OIL have played a major and vital role in catering to the energy needs of the country. However the task facing them is formidable. Both these companies have been operating under severe constraints and lack the required flexibility to operate under a competitive environment. They need to have access to world class technology. Their full potential to raise funds required to enhance equity reserves is to be fully tapped. Although they have been performing well within the constraints under which they were operating, steps have to be taken to equip them to operate in a more dynamic environment.

7.5. GAS AUTHORITY OF INDIA LIMITED (GAIL)

GAIL was incorporated in 1984 with the primary objective of constructing the cross country Hazira-Bijaipur-Jagdishpur (HBJ) gas pipeline. It is the only company in India handling post-exploration activities relating to Natural Gas, viz., transmission, processing, distribution and marketing of natural gas, its fractions and by products.

GAIL owns and operates one of the largest pipelines - the 1,800 km long HBJ pipeline system which carries 20 MMSCMD gas from the western coast of India to the central and northern parts of the country. Apart from this, GAIL has shorter pipeline networks supplying gas to industries from offshore/onshore Gas fields in the western, north-eastern and southern parts of the country.

It operates three LPG plants of installed capacity of 4,79,000 MTPA which are currently operating at 5,00,000 MTPA. In pursuance of its objective of utilising all fractions of gas and its derivatives for higher economic value, it has commissioned facilities for fractioning NGL to produce value added projects viz., Special Boiling Point Liquids (SBP), industrial solvents and Pentane.

During the year 1996-97 GAIL maintained high standards of reliable supply, ensuring uninterrupted supply of gas to all its customers along HBJ pipeline. To date, almost all GAIL's projects have been commissioned within the scheduled cost and time-frame and this has considerably contributed to the generation of surpluses and operating margins even in the initial stages after project commissioning. GAIL posted a record profit during the year 1996-97 and met all physical and financial Memorandum of Understanding (MOU) targets in the areas of turnover, profits, project completion, etc. In areas of operation, GAIL has been able to provide pipeline availability of 99.9%. The main factors contributing to the record turnover and profitability of the company have been an increase in gas handling through the HBJ pipeline and increase in the LPG production.

7.5.1. GAIL's performance at a glance

The financial and physical performance of GAIL for years 1993-94 to 1996-97 are shown in Tables 7.2 and 7.3 respectively.

Table 7.2: Physical Performance of GAIL

Description	Unit	1993-94	1994-95	1995-96	1996-97
Gas Sales	MCM	13,394	13,397	17,017	17,285
LPG/SBP/Others Production	'000 MT	423.53	422.76	588.22	610.52

Table 7.3: Financial Performance of GAIL

Description	Unit	1993-94	1994-95	1995-96	1996-97
Profits After Tax	Million $	91.71	105.41	147.42	172.85
Gross Internal Resource Generation	Million $	156.85	170.85	206.85	247.14

During the past year GAIL established a number of facilities for supply of gas to major new consumers. It is also implementing a number of projects which have been approved by the Government. A few of the significant ones are listed:

- Pipe laying for the expansion of HBJ system, Gas Rehabilitation and Expansion Project (GREP), completed ahead of schedule.
- Spur line to the IOC, Mathura completed and gas supply to the refinery commenced in December 96. Six pipelines have been completed during the year for supply of gas to consumers from isolated gas fields in Gujarat region.
- During the year, GAIL also launched its City Gas Distribution projects in Agra and Ferozabad and a pilot project in Delhi. Supply of gas to consumers from these projects is expected to commence shortly.
- In Mumbai, the GAIL-British Gas joint venture company, Mahanagar Gas has already provided connections to over 2,000 domestic and 10 commercial consumers in the city.

The company has on hand projects worth over $ 285.71 million, which are due for completion during 1997-98. These include setting up an integrated grassroots petrochemical complex at Pata in Uttar Pradesh (UP), LPG Lakwa project, LPG Usar project. The Pata facility in UP would house a LLDPE/HDPE swing plant with a capacity of 160,000 tpa, a gas processing unit with a capacity of 12.7 MMSCMD, a gas processing unit with a capacity of producing 300,000 tpa ethylene, 12,000 tpa propylene and a butene-1 unit of 10,000 tpa capacity. Apart from this, projects worth $857.14 million are currently awaiting final government approval. These include Gas Processing plant, Gandhar; LPG plant at Auraiya; and Kandla-Loni LPG pipeline project. Apart from the Auraiya project which could be ready by 1999, the rest would probably be ready by the turn of the century. GAIL is actively pursuing growth opportunities both, within and outside the country. It is exploring opportunities for participation in joint ventures overseas for transmission and distribution of gas, project management and construction and operation of gas based LPG plants.

The framework for the GAIL Euroissue has been finalised. There is a broad consensus on the approximate size of the float within the MOP&NG, the company and the finance ministry. The government had committed to ADB for divesting 30% of its holding in GAIL by December 1996. Till date however only 3.37% of the equity have been offloaded to the financial institutions and the employees.

7.6 LEGISLATION

At present there is no statute for controlling natural gas trade in India and GAIL is the de-facto monopoly gas transmitter. It has however been suggested that a Gas Act may be enacted by the Parliament to regulate inter-state transmission of gas. The Act may also provide for establishment of state level regulatory bodies. The Gas Act may provide for formation of an Independent Gas Regulatory Board. The formation of the Regulatory Body may be on the lines of the regulatory bodies in other nations for e.g. OFGAS in UK and / or the National Gas Regulatory Board in Argentina.

The Board would be an independent entity, comprising of professional members and its statutory powers would stem from the Gas Act. The functions of the Regulatory Body would include: laying down of technical and administrative procedures, public gas supply code, acquisition of rights to use pipelines, construction and operating standards of pipelines, developing competition through 'common carrier principle' for pipelines, fixing of tariffs and monitoring standards of quality, safety and environment.

7.7 INTERACTION BETWEEN ONGC, OIL AND GAIL

ONGC and OIL constitute the upstream sector of the hydrocarbon industry while GAIL looks into the transportation and marketing of natural gas. They operate under the overall charge of MOP&NG which influences the pattern of natural gas consumption by administered allocation of gas through the Gas Linkage Committee and the prices through the Administered Price Mechanism. Their present interaction is limited to the coordination to ensure smooth and regular transportation of the gas to the consumers.

In future however, with the deregulation of the industry, their relationship is expected to become more involved and complex. The emerging factors include:

- Entry of private sector in oil and gas exploration. To optimally utilise the existing infrastructure resources it has been suggested that the principle of common carrier/common access be followed for the use of gas pipelines by any producer/marketer. Under such circumstances the transportation and distribution charges will have to be on more commercial terms than as dictated by the APM.
- In a move to become more integrated entities it is expected that they will form collaborations among themselves and with other players to serve the market more effectively and efficiently.

- Further, with the deregulation of the sector, the restrictions on the PSU's are expected to be removed. Thus it is likely that the ONGC and OIL may move into the downstream sector and GAIL into the exploration and production area.

7.8. RECENT MARKET DEVELOPMENTS

The Ministry of Petroleum and Natural Gas, in a recent seminar on oil and gas, declared natural gas as one of the thrust areas for investment and called upon private companies to invest heavily in this sector. As per the Ministry's internal time-frame, a new price structure for Natural Gas is expected to be in place w.e.f. July 1, 1997. The proposed hike works out 15% increase in the retention price for ONGC and GAIL, and a 15-20% hike for the consumers.

The Union Cabinet has recently approved the formation of a joint venture company by GAIL, IOC, BPCL and ONGC for import of LNG and indigenous development of this fuel in a big way. The joint venture company will have an authorised capital of Rs. 1,200 crore and the public sector oil companies will hold 50% of the equity. The proposal envisages long-term contractual relations between buyers and sellers of LNG. It is a significant measure towards establishing the LNG chain linking gas fields, liquefaction of gas, shipping, regassification and end use of the fuel in power generation and fertiliser manufacture. The joint venture when setup will have a strong presence in the Indian energy market with a good credit rating, better bargaining strength and a nation wide marketing infrastructure as well as expertise in developing LNG links.

As a follow up to the first ever offer for the supply of LNG, for which GAIL had received 17 offers, it has shortlisted 8 companies based only on the technical bids. GAIL will now carry out discussion on the commercial terms, i.e., the price bids, with these companies which include Shell, Mobil, QGPC, Petronas and Enron among others. There is a provision for a second list under the current plan if the need arises.

GAIL has recently entered into a 20 year agreement with the Command-Marubeni-Videocon combine for the purchase of gas from Ravva offshore oil and gas field. The agreement is for the purchase of 1.0 MMSCMD and the price of the gas is linked to the basket of high sulphur fuel oil. The agreement specifies clearly that there would be mutually binding and equal take or pay provision on case of either failure to supply on the part of the producer or failure to lift the gas on the part of

GAIL. It also provides for discounts on quality and quantity and has a provision for handling shortfalls, etc., as per standard terms of international contracting.

The Oil Ministry is preparing a Cabinet note for selling Government's 60% share in Lubrizol India Ltd (LIL) to ONGC. This is for the first time that Government has proposed divesting majority stake in an oil company. As per the proposal, government will sell its entire stake to ONGC (50%) and Lubrizol (10%). The move also pioneers ONGC's diversification downstream. The Government of India is also planning disinvestment of its equity in the GAIL. The move follows the recent recommendation of the Disinvestment Commission. The commission has however suggested not to divest the shares of Oil and Gas majors till the issue of Administered Price Mechanism (APM) is resolved and the organisational changes are in place. But with the government agreeing in principle to deregulate the sector, oil giants like ONGC and GAIL stand to benefit substantially in the coming years.

ONGC has decided to join hands with Petrobras of Brazil to undertake deep water exploration in India. The oil giants will drill two wells, one each on East and West coast, by the end of the year. Preliminary surveys have been completed on the East and the West coasts and four prospective areas, two each in East and West offshore, have been identified based on the seismic surveys. This would be the first ever deep-sea exploitation project in India which would involve a drilling beyond 200 meters of the water depth. ONGC has also hired the services of the Norwegian firm, PGS, in order to check the declining production from the Bombay High. It is also likely to go in for a strategic alliance with foreign oil companies to enhance the crude oil output from the Neelam Field.

ONGC is all set to implement the restructuring exercise as recommended by the management consultants Mckinsey and Company. The recommendations include autonomous handling of the projects, increased investment in hardware and slowly moving away from areas like drilling and seismic data processing which can be hived off as separate Strategic Business Units (SBUs) or profit centres.

7.9. POLICY INITIATIVES

In pursuance of its policy of economic liberalisation the government has taken several initiatives in opening up the hydrocarbon sector to the private enterprises. These include offering of exploration and development blocks, allowing entry into refinery sector, parallel marketing of LPG and Superior Kerosene Oil (SKO) by private parties and import by actual users of some products like Naphtha, LSHS has

been decanalised. Thus, the refining and marketing of petroleum products, once an exclusive privilege of the PSUs, will now be carried out by many private parties. The Petroleum Ministry is also proposing to set up a new exploration company, in addition to ONGC and OIL. Although the discussions for the proposal are yet at the preliminary stages only, it is suggested that the Government stake be limited to only 50% so as to create a lean organisation capable of taking quick, decisive action.

In order to eliminate much of the uncertainty that exists in the entire industry, the Government has drawn up an ambitious blueprint aimed at easing the oil crisis. The four key objectives are: total decontrol of the sector in three phases by the year 2002; granting full autonomy to both ONGC and OIL, as well as ensuring they receive international prices for their crude; encouraging Indian companies to prospect for oil overseas so that part of the output can be supplied to India; and putting in place a new domestic exploration licensing policy to attract private investment.

With the entry of new players, in the market, competition is bound to increase. The PSUs shall have an important role to play even in the deregulated environment given the sheer magnitude of their domain under the present scenario. The PSUs are the monopoly owners of the industry infrastructure base and the success of the program will depend on managing these assets optimally. Further during the transition phase they will have to ensure that strategic reserves are maintained to handle any crisis. This competition should be perceived as an opportunity by the PSUs and they should try to emerge as the best in terms of productivity and efficiency.

In the latest strategy to obviate the oil pool account deficit, which is expected to go up to $ 7.0 billion by March 31,1998, the oil companies may be issued bonds by the Government of India. As per the proposal, through an ingenuous "financial engineering", the entire accumulated oil pool account deficit at the end of March 1997 will be wiped out by government paying up an amount to the OCC, which in turn will pay up the outstanding dues to the oil marketing companies. These public sector companies will then utilise the proceeds to buy long--term government debt instruments (Gilts). Thus the entire accumulated deficit will stand transferred to the government account as its long--term debt. Although the oil marketing companies will be forced to invest in government securities, they would not be necessarily tied down to holding the debt instruments because in a case of liquidity crunch, they can offload the debt instruments in the secondary market.

The government has finally realised the importance of the massive investment required in the exploration and production sector and has come out with the New Exploration Licensing Policy (NELP). The main features of this policy include allowing private companies to bid for exploration blocks independently, paying ONGC and OIL international rates for the supply of crude, establishing a provision for royalty adjustment in the case of economically marginal fields and to substitute the bidding rounds--with a continuous bidding system. The Ministry is also proposing a new exploration bidding round in July, 1997 which will kick off the New Exploration Licensing Policy. Much of the groundwork for the process--including grid formulation, identification of blocks etc. has been completed.

Though the NELP appears to streamline some of the policy regulations and measures, there are many issues which need immediate attention, for e.g. the bureaucratic delays in the process of award of tenders. Whether the policy is successful or not is thus dependent on the political will of the government and remains to be seen, but it surely is a step in the right direction.

CHAPTER 8
NATURAL GAS SCENARIO IN ASSAM AND TRIPURA

8.1. INTRODUCTION

The law and order situation in the North East have not been very conductive to intensive exploration and industrial activities. As a result, the market has not developed even at a discounted gas price. Considerable quantities of gas have been flared in the past, and all efforts are presently under way to reduce flaring to the minimum required. For a proper local market to develop, the development of infrastructure is of paramount importance besides an improvement in the law and order situation. Some fiscal incentives may also be necessary for expeditious industrialisation of that area. Further exploration and production of natural gas would become viable only when, in the course of time, the producer is given remunerative prices, as exploration and production are relatively high cost activities in this region. The North East is characterised by excess production of gas which cannot be completely be utilised within the state. Taking the gas out of North East is a complicated problem. Natural gas production is predominantly in the states of Assam and Tripura. The production for the states is as shown in Table 8.1.

Table 8.1: Gross production of natural gas in Assam and Tripura.

	1992-93	1993-94	1994-95	1995-96	1996-97	CARG
Assam	2034 (38%)	1978 (39.4%)	1909 (32.3%)	1881	1960	-1%
Tripura	115	102	97	130	156	6%

Note: Numbers in parenthesis indicate the percentage of reinjected plus flared gas from the gross production.

In the late eighties, government allowed use of natural gas in power generation. Since then, the demand for natural gas has soared. After the inception of Gas Authority of India Limited (GAIL) in 1984, gas flaring has been reduced from 42% in 1983-84 to only 10.5% for the production year 1994-95 for the whole country. For the North East this figure is more modest at about 32%. According to a recent report from Oil India Limited, the flaring has been reduced to about 19% during the year 1995-96. In Tripura, unlike Assam, there is no flaring of gas, as the entire production is non-associate gas. The reduction in flaring has been possible due to installation of gas storage-cum-flowback facility. Sector wise consumption statistics indicate that the majority of the gas is being used for power generation followed by petrochemicals and fertilisers. The demand projections by various sectors for natural gas during the year 2001-02 are depicted in Table 8.2.

Table 8.2: Estimated sector-wise demand for natural gas in south and east India during the year 2001-02.

Sector	**Requirements (BCM)**	
	East	South
Fertiliser	0.36	7.95
Power	0.91	6.60
Sponge Iron	0.18	4.88
Glass	-	6.66
Others	1.47	5.27
Total	**2.92**	**31.36**

8.2. ASSAM

Natural gas reserves in Assam are mostly associate gas and have been found in commercial quantities at several locations like Jorajan, Moran, Japjan, Shalmari, Naharkatiya, and Dikom. The recoverable reserves in Assam are about 150 BCM and could permit a production level of 20 MMSCMD with reserves to production ratio of about 20 years. ONGC and OIL are engaged in the production activity and have recoverable reserves of about 90 BCM and 60 BCM respectively.

The total production during the year 1996-97 was 1,960 MCM, and the major consumers in the state are the power, fertiliser, and the tea grids. Some of the large consumers are: Assam State Electricity Board, Hindustan Fertiliser Corporation Limited, Indian Oil Corporation and Assam Gas Company. The offtake of the gas by these sectors have been consistently below the allocation, and this has resulted in a surplus position during the past few years in the state.

8.2.1. Existing customers in Assam

8.2.1.1. Hindustan Fertiliser Corporation (HFC)

The Hindustan Fertiliser Corporation plant in Assam comprises of 3 production units. These three units have an aggregate capacity of 1,400 tons/day of ammonia production. Unit No. 1 has a capacity of 200 tons/day and units 2 and 3 have a capacity of 600 tons/day each. The allocation of gas to this plant has been 1.762 MMSCMD from OIL and 0.45 MMSCMD from ONGC. In contrast to the allocations made for the HFC plant, the trend for offtake has been dismal at around 1.3 MMSCMD. The offtake of gas by HFC has ranged between 57% and 67% between 1989-1993. The maximum possible gas offtake in HFC under ideal conditions has been given as follows:

Unit 1:	0.12 MMSCMD (95% of the capacity utilisation)
Unit 2:	0.76 MMSCMD (80% of capacity utilisation)
Unit 3:	1.17 MMSCMD (100% capacity utilisation)

The total maximum requirement works out to be about 2.05 MMSCMD. Thus, even under the best possible conditions, the actual offtake of gas would be 2.05 MMSCMD against the allocated 2.12 MMSCMD.

8.2.1.2. Assam State Electricity Board (ASEB)

The gas allocations for the various ASEB units are as follows:

Allocation by ONGC	0.865 MMSCMD
Allocation by OIL	0.913 MMSCMD

Thus against a total allocation of 1.77 MMSCMD, the maximum demand by various units is as follows:

Namrup Thermal Power Station:	0.897 MMSCMD
Lakwa Thermal Power Station:	0.69 MMSCMD
Mobile Gas Stations at Geleki and Kathalguri:	0.174 MMSCMD

The maximum demand for power in 1993-94 was about 1.76 MMSCMD, but the actual consumption was about 0.573 MMSCMD.

8.2.1.3. Assam Petrochemicals Limited (APL)

The offtake of this petrochemical plant has been 0.119 MMSCMD against an allocation of 0.138 MMSCMD.

8.2.1.4. Tea Grids

The total allocated natural gas for tea grids has been about 0.60 MMSCMD, whereas the actual offtake has been about 0.35 MMSCMD.

8.2.1.5. Assam Gas Company, Duliajan (AGC)

The Assam Gas Company functions as a distributing agency, including supplying to HFC and ASEB, and some tea gardens. AGC has been allocated 0.65 MMSCMD for domestic supplies. The offtake has been much less, about 0.04 MMSCMD.

8.2.2. New Ventures

8.2.2.1. Numaligarh Refinery

The expected gas requirement for this refinery is about 1.2 MMSCMD.

8.2.2.2. Gas Cracker

This proposed petrochemical plant is expected to have an offtake of about 1.0 MMSCMD.

8.2.2.3. Power Projects

Expected projects in Power sector include Namrup Extension, and new units at Barak Valley and Kathalguri Power station. The total offtake is expected to be about 3.0 MMSCMD.

8.2.3. Summary for Assam

To summarise, the allocation of natural gas is about 5 MMSCMD, of which 2.53 MMSCMD is being used, with a potential of a maximum use of about 4.13 MMSCMD. The expected maximum consumption for the year 1996-97 is expected to be around 5.28 MMSCMD. The current maximum of expected 5.28 MMSCMD for the year 1996-97 has been projected to grow to 9.38 MMSCMD by the year 2001-02.

8.3. TRIPURA

Most of the recoverable reserves of 46 BCM in Tripura are of non-associate gas. The prognosticated resources of the state are approximately 400 BCM and exploration activities have yielded results in Baramura, Rokhia, Agartala Dome, and Gogalia. Since large portion of the prospective sites has not been explored, there is a distinct possibility of establishing new reserves but further investments in exploration and development would depend on the prospects of utilisation.

In Tripura the major consumer of the gas has been the power sector and the rest of the gas is consumed by the brick kilns and the Tripura Natural Gas Company.

8.3.1. Current Allocation and Consumption

The allocation of customers and the range of their current offtake are indicated below:

1. Brick Kilns	0.01 MMSCMD
2. Tripura State Electricity Department:	0.34 MMSCMD
3. Tripura National Gas Company:	200 cubic meters/day

The range of offtake for the natural gas ranges between 0.25 to 0.36 MMSCMD. The demand for natural gas from brick kilns is between November and April, and is purely seasonal nature. Unlike Assam, there is no flaring of gas, as the entire production is non-associate gas, and can be controlled up on the requirement.

The future expected allocations to various users like power, industrial consumers, and for production of CNG is expected to be about 1.41 MMSCMD.

8.4. CONCLUSION

The possible ranges of demand and supply for natural gas in Assam and Tripura on the basis of currently identified customers has been summarised in Table 8.3.

Table 8.3: Possible supply and demand range of natural gas in Assam and Tripura

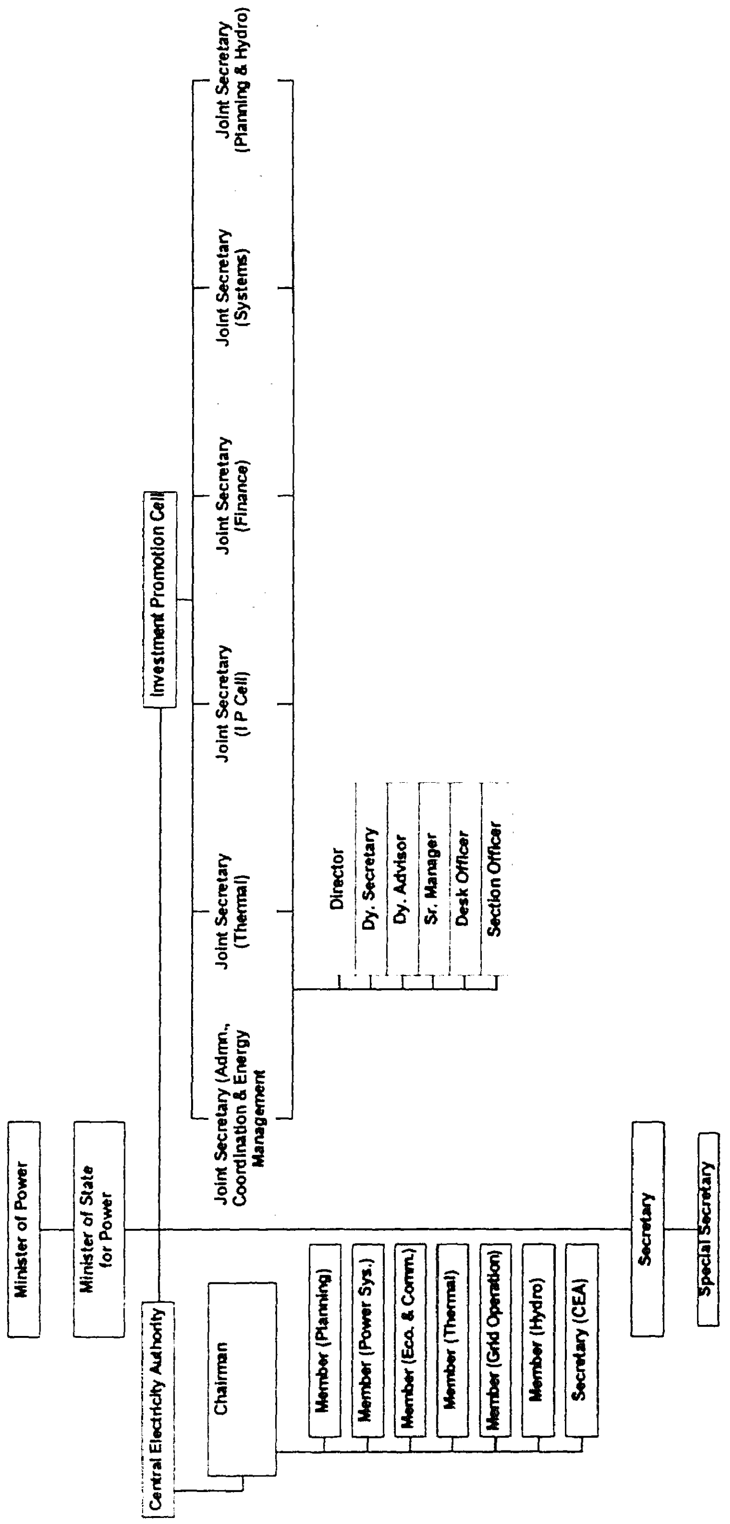
MMSCMD

	1996-97		2001-02	
State	**Supply**	**Demand**	**Supply**	**Demand**
Assam	5.3-6	max. of 5.3	5.7-8.5	6.5-9.4
Tripura	0.43-0.5	0.25-0.36	0.8-1.75	0.4-1.8

It is difficult to make demand-supply estimates for Tripura for the year 2001-02, because no worthwhile estimates can be made in the absence of more firm information about additional customers. The production potential in Tripura has, however, been variously assessed as between 3 to 6 MMSCMD, subject to adequate exploration and development efforts, but investments on exploration and/or development would be linked to development of new demand and vice-versa. If we take in to account the possibility of gas demand in the power sector in Assam not materialising fully because of plant availability and energy demand problems, there is a potential for excess gas supply situation continuing in both Assam and Tripura.

APPENDICES

Appendix 3.1: Ministry of Power - Simplified organisation chart


Minister of Power
Minister of State for Power
Central Electricity Authority
Chairman
Member (Planning)
Member (Power Sys.)
Member (Eco. & Comm.)
Member (Thermal)
Member (Grid Operation)
Member (Hydro)
Secretary (CEA)
Secretary
Special Secretary
Investment Promotion Cell
Joint Secretary (Admn., Coordination & Energy Management
Joint Secretary (Thermal)
Joint Secretary (I P Cell)
Joint Secretary (Finance)
Joint Secretary (Systems)
Joint Secretary (Planning & Hydro)
Director
Dy. Secretary
Dy. Advisor
Sr. Manager
Desk Officer
Section Officer

Appendix 5.1: Imputed value calculation for conventional coal plants

COMMON INFORMATION FOR CALCULATION OF IMPUTED VALUES — CONVENTIONAL COAL FIRED PLANTS

Delivered price for Coal		Imported coal	Indigenous coal	Natural gas
Pithead cost	Rs/T		357	
Royalty	Rs/T		50	
Stowing duty	Rs/T		4	
Sales tax	%		4	
Sales tax	Rs/T		14	
f.o.b. price	Rs/T		425	
c.i.f. price	Rs/T	1925		
Import duty @10%	Rs/T	193		
Total c.i.f.	Rs/T	2118		
Port/Mine handling charges	Rs/T	225	21	
Total price	Rs/T	2343	446	
Imputed value related to capital cost	Units			
1.Capacity	MW	1	1	1
2.Capacity utilisation	(%)	68.5	68.5	68.5
3.Annual output	MWh	6000.6	6000.6	6000.6
4.Auxiliary consumption	(%)	9.5	9.5	3
5.Units sent out/annum	MWh	5430.54	5430.54	5820.58
6.Capital cost	Rs.million	37.86	35.97	24.5
7.Phasing of investment				
Year -3		0.2	0.2	0
Year -2		0.3	0.3	0.2
Year -1		0.4	0.4	0.5
Year -0		0.1	0.1	0.3
Total		1	1	1
8.Discount factor		0.12	0.12	0.12
9.NPV factor		1.21	1.21	1.11
10.NPV of capital cost	Rs.million	45.63	43.35	27.22
11.Life of plant	Years	25	25	20
12.CRF		0.13	0.13	0.13
13.Annutised capital cost	Rs.million	5.82	5.53	3.64
14.Capital cost/KWh of power	Rs./KWh	1.07	1.02	0.63
15.Calorific value	K.cal/Kg	6250	4200	
Calorific value	K.cal/cu.Meter			8760
16.Heat rate for coal based plants	K.cal/KWh	2500	2500	
Heat rate for CC plants	K.cal/KWh			1625
17.N.gas consumption/KWh (gross)	NM^3/kWh			0.19
18.N.gas consumption/KWh (net)	NM^3/kWh			0.18
19.Imputed value related to capital cost	Rs/1000 NM^3	2475.18	2177.94	
Imputed value related to fixed operating cost				
1.Fixed operating cost as % of capital cost	(%)	2.5	2.5	2.5
2. Total fixed operating cost	Rs. million	0.9465	0.89925	0.61
3. Fixed operating cost (Rs./KWh)	Rs/KWh	0.17	0.17	0.11
4.Imputed value related to fixed optg.cost	Rs/1000 NM^3	383.81	335.46	
Sp.consumption of raw materials and utilities				
Coal	T/MWh	0.40	0.60	
Fuel oil	T/MWh	0.00	0.00	
Natural gas	1000 NM^3/MWh			0.18

IMPUTED VALUES (CONVENTIONAL COAL FIRED)			
LOCATION: CALCUTTA			
Origin	Destination	Distance (KMS)	
Haldia (Imported)	Calcutta	79	
Asansol (Indigenous)	Calcutta	200	
Delivered price for Coal		Imported coal	Indigenous coal
Transportation cost	Rs/T	92	153
Landed Cost	Rs/T	2434	599
Cost of raw materials			
Gross	Rs/kWh	0.98	0.36
Net	Rs/kWh	0.88	0.32
Imputed value of natural gas			
Related to raw materials	Rs./1000NM^3	4907	1803
Total imputed value			
	Rs./1000NM^3	7766	4316
Imputed value of natural gas			
	US$/MMBtu	**6.40**	**3.56**
Cost of generation			
	Rs/kWh	2.13	1.51
	US cents/kWh	**6.08**	**4.31**

IMPUTED VALUES (CONVENTIONAL COAL FIRED)

LOCATION: PARADIP

Origin	Destination	Distance (KMS)	
Paradip (Imported)	Paradip	0	
Talcher (Indigenous)	Paradip	180	
Delivered price for Coal		Imported coal	Indigenous coal
Transportation cost	Rs/T	0	141
Landed Cost	Rs/T	2343	587
Cost of raw materials			
Gross	Rs/kWh	0.94	0.35
Net	Rs/kWh	0.85	0.32
Imputed value of natural gas			
Related to raw materials	Rs./1000NM^3	4723	1767
Total imputed value			
	Rs./1000NM^3	7582	4281
Imputed value of natural gas			
	US$/MMBtu	**6.25**	**3.53**
Cost of generation			
	Rs/kWh	2.10	1.50
	US cents/kWh	**5.99**	**4.29**

IMPUTED VALUES (CONVENTIONAL COAL FIRED)

LOCATION: VISHAKHAPATNAM

Origin	Destination	Distance (KMS)	
Vishakhapatnam (Imported)	Vishakhapatnam	0	
Dornakal (Indigenous)	Vishakhapatnam	488	
Delivered price for Coal		Imported coal	Indigenous coal
Transportation cost	Rs/T	0	337
Landed Cost	Rs/T	2343	783
Cost of raw materials			
Gross	Rs/kWh	0.94	0.47
Net	Rs/kWh	0.85	0.42
Imputed value of natural gas			
Related to raw materials	Rs./1000NM^3	4723	2353
Total imputed value			
	Rs./1000NM^3	7582	4866
Imputed value of natural gas			
	US$/MMBtu	**6.25**	**4.01**
Cost of generation			
	Rs/kWh	2.10	1.61
	US cents/kWh	**5.99**	**4.59**

IMPUTED VALUES (CONVENTIONAL COAL FIRED)

LOCATION: MADRAS

Origin	Destination	Distance (KMS)	
Madras (Imported)	Madras	0	
Talcher (Indigenous)	Madras	1357	
Delivered price for Coal		**Imported coal**	**Indigenous coal**
Transportation cost	Rs/T	0	933
Landed Cost	Rs/T	2343	1379
Cost of raw materials			
Gross	Rs/kWh	0.94	0.82
Net	Rs/kWh	0.85	0.74
Imputed value of natural gas			
Related to raw materials	Rs./1000NM^3	4723	4138
Total imputed value			
	Rs./1000NM^3	7582	6651
Imputed value of natural gas			
	US$/MMBtu	**6.25**	**5.48**
Cost of generation			
	Rs/kWh	2.10	1.93
	US cents/kWh	**5.99**	**5.51**

Appendix 5.2: Imputed value calculation for IGCC coal plants

COMMON INFORMATION FOR CALCULATION OF IMPUTED VALUES — IGCC COMBINED CYCLE COAL FIRED PLANTS				
Delivered price for Coal		**Imported coal**	**Indigenous coal**	**Natural gas**
Pithead cost	Rs/T		357	
Royalty	Rs/T		50	
Stowing duty	Rs/T		4	
Sales tax	%		4	
Sales tax	Rs/T		14	
f.o.b. price	Rs/T		425	
c.i.f. price	Rs/T	1925		
Import duty @10%	Rs/T	193		
Total c.i.f.	Rs/T	2118		
Port/Mine handling charges	Rs/T	225	21	
Total price	Rs/T	2343	446	
Imputed value related to capital cost	**Units**			
1.Capacity	MW	1	1	1
2.Capacity utilisation	(%)	68.5	68.5	68.5
3.Annual output	MWh	6000.6	6000.6	6000.6
4.Auxiliary consumption	(%)	20	20	3
5.Units sent out/annum	MWh	4800.48	4800.48	5820.58
6.Capital cost	Rs.million	47.3	58.2	24.5
7.Phasing of investment				
Year -3		0.2	0.2	0
Year -2		0.3	0.3	0.2
Year -1		0.4	0.4	0.5
Year -0		0.1	0.1	0.3
Total		1	1	1
8.Discount factor		0.12	0.12	0.12
9.NPV factor		1.21	1.21	1.11
10.NPV of capital cost	Rs.million	57.01	70.15	27.22
11.Life of plant	Years	20	20	20
12.CRF		0.13	0.13	0.13
13.Annutised capital cost	Rs.million	7.63	9.39	3.64
14.Capital cost/KWh of power	Rs./KWh	1.59	1.96	0.63
15.Calorific value	K.cal/Kg	6250	4200	
Calorific value	K.cal/cu.Meter			8760
16.Heat rate for coal based plants	K.cal/KWh	1625	1625	
Heat rate for CC plants	K.cal/KWh			1625
17.N.gas consumption/KWh (gross)	NM^3/kWh			0.19
18.N.gas consumption/KWh (net)	NM^3/kWh			0.18
19.Imputed value related to capital cost	Rs/1000 NM^3	5357.15	7393.40	
Imputed value related to fixed operating cost				
1.Fixed operating cost as % of capital cost	(%)	2.5	2.5	2.5
2. Total fixed operating cost	Rs. million	1.1825	1.455	0.61
3. Fixed operating cost (Rs./KWh)	Rs/KWh	0.25	0.30	0.11
4.Imputed value related to fixed optg.cost	Rs/1000 NM^3	784.16	1099.63	
Sp.consumption of raw materials and utilities				
Coal	T/MWh	0.26	0.39	
Natural gas	1000 NM^3/MWh			0.18

IMPUTED VALUES (IGCC COMBINED CYCLE COAL FIRED)			
LOCATION: CALCUTTA			
Origin	Destination	Distance (KMS)	
Haldia (Imported)	Calcutta	79	
Asansol (Indigenous)	Calcutta	200	
Delivered price for Coal		Imported coal	Indigenous coal
Transportation cost	Rs/T	92	153
Landed Cost	Rs/T	2434	599
Cost of raw materials			
Gross	Rs/kWh	0.63	0.23
Net	Rs/kWh	0.51	0.19
Imputed value of natural gas			
Related to raw materials	Rs./1000NM^3	2823	1039
Total imputed value			
	Rs./1000NM^3	8964	9532
Imputed value of natural gas			
	US$/MMBtu	**7.38**	**7.85**
Cost of generation			
	Rs/kWh	2.34	2.45
	US cents/kWh	**6.70**	**6.99**

IMPUTED VALUES (IGCC COMBINED CYCLE COAL FIRED)			
	LOCATION: PARADIP		
Origin	Destination	Distance (KMS)	
Paradip (Imported)	Paradip	0	
Talcher (Indigenous)	Paradip	180	
Delivered price for Coal		Imported coal	Indigenous coal
Transportation cost	Rs/T	0	141
Landed Cost	Rs/T	2343	587
Cost of raw materials			
Gross	Rs/kWh	0.61	0.23
Net	Rs/kWh	0.49	0.18
Imputed value of natural gas			
Related to raw materials	Rs./1000NM^3	2717	1019
Total imputed value			
	Rs./1000NM^3	8858	9512
Imputed value of natural gas			
	US$/MMBtu	**7.30**	**7.84**
Cost of generation			
	Rs/kWh	2.33	2.44
	US cents/kWh	**6.64**	**6.98**

IMPUTED VALUES (IGCC COMBINED CYCLE COAL FIRED)			
LOCATION: VISHAKHAPATNAM			
Origin	Destination	Distance (KMS)	
Vishakhapatnam (Imported)	Vishakhapatnam	0	
Dornakal (Indigenous)	Vishakhapatnam	488	
Delivered price for Coal		Imported coal	Indigenous coal
Transportation cost	Rs/T	0	337
Landed Cost	Rs/T	2343	783
Cost of raw materials			
Gross	Rs/kWh	0.61	0.30
Net	Rs/kWh	0.49	0.24
Imputed value of natural gas			
Related to raw materials	Rs./1000NM^3	2717	1355
Total imputed value			
	Rs./1000NM^3	8858	9848
Imputed value of natural gas			
	US$/MMBtu	**7.30**	**8.11**
Cost of generation			
	Rs/kWh	2.33	2.50
	US cents/kWh	**6.64**	**7.15**

IMPUTED VALUES (IGCC COMBINED CYCLE COAL FIRED)

LOCATION: MADRAS

Origin	Destination	Distance (KMS)	
Madras (Imported)	Madras	0	
Talcher (Indigenous)	Madras	1357	
Delivered price for Coal		Imported coal	Indigenous coal
Transportation cost	Rs/T	0	1379
Landed Cost	Rs/T	2343	1825
Cost of raw materials			
Gross	Rs/kWh	0.61	0.71
Net	Rs/kWh	0.49	0.57
Imputed value of natural gas			
Related to raw materials	Rs./1000NM^3	2717	3148
Total imputed value			
	Rs./1000NM^3	8858	11641
Imputed value of natural gas			
	US$/MMBtu	**7.30**	**9.59**
Cost of generation			
	Rs/kWh	2.33	2.83
	US cents/kWh	**6.64**	**8.07**

Appendix 5.3: Imputed value calculation for naphtha fired plants

COMMON INFORMATION FOR CALCULATION OF IMPUTED VALUES — NAPHTHA FIRED COMBINED CYCLE PLANTS				
Imputed value related to capital cost		Imported Naphtha	Indigenous Naphtha	Natural gas
1.Capacity	MW	1.00	1.00	1.00
2.Capacity utilisation	(%)	68.50	68.50	68.50
3.Annual output	MWh	6000.60	6000.60	6000.60
4.Auxiliary consumption	(%)	3.00	3.00	3.00
5.Units sent out/annum	MWh	5820.58	5820.58	5820.58
6.Capital cost	Rs. million	24.50	24.50	24.50
7.Phasing of investment				
Year -2		0.20	0.20	0.20
Year-1		0.50	0.50	0.50
Year-0		0.30	0.30	0.30
Total		1.00	1.00	1.00
8.Discount factor		0.12	0.12	0.12
9.NPV factor		1.11	1.11	1.11
10.NPV of capital cost	Rs.million	27.22	27.22	27.22
11.Life of plant	Years	20.00	20.00	20.00
12.CRF		0.13	0.13	0.13
13.Annutised capital cost	Rs.million	3.64	3.64	3.64
14.Capital cost/KWh of power	Rs./KWh	0.63	0.63	0.63
15.Calorific Value	K.cal/NM^3			8760.00
Calorific Value	K.cal/Kg	10560.00	10560.00	
16.Heat rate for CC plants	K.cal/KWh	1625.00	1625.00	1625.00
17.N.gas consumption/KWh (gross)	NM^3/KWh			0.19
18.N.gas consumption/KWh (net)	NM^3/KWh			0.18
19.Imputed value related to capital cost	Rs/1000 NM^3			0.00
Imputed value related to fixed operating cost				
1. Fixed operating cost as % of capital cost	%	2.50	2.50	2.50
2.Total Fixed operating cost	Rs. million	0.61	0.61	0.61
3.Fixed operating cost(Rs/KWh)	Rs/KWh	0.11	0.11	0.11
4.Imputed value related to fixed operating cost	Rs/1000 NM^3			0.00
Sp. Consumption of raw materials and utilities				
Naphtha	T/MWh	0.15	0.15	
Natural gas	1000 NM^3/MWh			0.18

IMPUTED VALUES (NAPHTHA FIRED COMBINED CYCLE)

	LOCATION: CALCUTTA		
Origin	Destination	Distance (KMS.)	
Calcutta (Imported)	Calcutta	0	
Haldia (Indigenous)	Calcutta	79	
Delivered Price for Naphtha		Imported Naphtha	Indigenous Naphtha
Ex-storage price	Rs./T	5985	6683
Sales tax	Rs./T	0	2673
Excise duty	Rs./T	0	1002
Countervailing duty	Rs./T	898	0
Delivered price	Rs./T	6883	7686
Transportation cost	Rs./T	0	176
Landed Cost			
Calcutta	Rs./T	6883	7862
Cost of raw materials			
Gross	Rs/kWh	1.06	1.21
Net	Rs/kWh	1.03	1.17
Imputed value of natural gas			
Related to raw materials	Rs./1000 NM^3	5710	6522
Total Imputed value			
	Rs./1000 NM^3	5710	6522
Imputed value of natural gas			
	US$/MMBtu	**4.70**	**5.37**
Cost of generation			
	Rs/kWh	1.76	1.90
	US cents/kWh	**5.02**	**5.44**

IMPUTED VALUES (NAPHTHA FIRED COMBINED CYCLE)			
LOCATION: PARADIP			
Origin	Destination	Distance (KMS.)	
Paradip (Imported)	Paradip	0	
Haldia (Indigenous)	Paradip	422	
Delivered Price for Naphtha		Imported Naphtha	Indigenous Naphtha
Ex-storage price	Rs./T	5985	6683
Sales tax	Rs./T	0	2673
Excise duty	Rs./T	0	1002
Countervailing duty	Rs./T	898	0
Delivered price	Rs./T	6883	7686
Transportation cost	Rs./T	0	611
Landed Cost			
Paradip	Rs./T	6883	8297
Cost of raw materials			
Gross	Rs/kWh	1.06	1.28
Net	Rs/kWh	1.03	1.24
Imputed value of natural gas			
Related to raw materials	Rs./1000 NM^3	5710	6883
Total Imputed value			
	Rs./1000 NM^3	5710	6883
Imputed value of natural gas			
	US$/MMBtu	**4.70**	**5.67**
Cost of generation			
	Rs/kWh	1.76	1.97
	US cents/kWh	**5.02**	**5.63**

IMPUTED VALUES (NAPHTHA FIRED COMBINED CYCLE)

LOCATION: VISHAKHAPATNAM

Origin	Destination	Distance (KMS.)	
Vishakhapatnam (Imported)	Vishakhapatnam	0	
Vishakhapatnam (Indigenous)	Vishakhapatnam	0	
Delivered Price for Naphtha		Imported Naphtha	Indigenous Naphtha
Ex-storage price	Rs./T	5985	6683
Sales tax	Rs./T	0	2673
Excise duty	Rs./T	0	1002
Countervailing duty	Rs./T	898	0
Delivered price	Rs./T	6883	7686
Transportation cost	Rs./T	0	0
Landed Cost			
Vishakhapatnam	Rs./T	6883	7686
Cost of raw materials			
Gross	Rs/kWh	1.06	1.18
Net	Rs/kWh	1.03	1.15
Imputed value of natural gas			
Related to raw materials	Rs./1000 NM^3	5710	6376
Total Imputed value			
	Rs./1000 NM^3	5710	6376
Imputed value of natural gas			
	US$/MMBtu	**4.70**	**5.25**
Cost of generation			
	Rs/kWh	1.76	1.88
	US cents/kWh	**5.02**	**5.37**

IMPUTED VALUES (NAPHTHA FIRED COMBINED CYCLE)

LOCATION: MADRAS

Origin	Destination	Distance (KMS.)	
Madras (Imported)	Madras	0	
Madras (Indigenous)	Madras	0	
Delivered Price for Naphtha		Imported Naphtha	Indigenous Naphtha
Ex-storage price	Rs./T	5985	6683
Sales tax	Rs./T	0	2673
Excise duty	Rs./T	0	1002
Countervailing duty	Rs./T	898	0
Delivered price	Rs./T	6883	7686
Transportation cost	Rs./T	0	0
Landed Cost			
Madras	Rs./T	6883	7686
Cost of raw materials			
Gross	Rs/kWh	1.06	1.18
Net	Rs/kWh	1.03	1.15
Imputed value of natural gas			
Related to raw materials	Rs./1000 NM^3	5710	6376
Total Imputed value			
	Rs./1000 NM^3	5710	6376
Imputed value of natural gas			
	US$/MMBtu	**4.70**	**5.25**
Cost of generation			
	Rs/kWh	1.76	1.88
	US cents/kWh	**5.02**	**5.37**

Appendix 5.4: Imputed value calculation for fuel oil fired plants

COMMON INFORMATION FOR CALCULATION OF IMPUTED VALUES — FUEL OIL FIRED COMBINED CYCLE PLANTS				
Imputed value related to capital cost		Imported Fuel Oil	Indigenous Fuel Oil	Natural gas
1.Capacity	MW	1.00	1.00	1.00
2.Capacity utilisation	(%)	68.50	68.50	68.50
3.Annual output	MWh	6000.60	6000.60	6000.60
4.Auxiliary consumption	(%)	3.00	3.00	3.00
5.Units sent out/annum	MWh	5820.58	5820.58	5820.58
6.Capital cost	Rs. million	25.11	25.11	24.50
7.Phasing of investment				
Year -2		0.20	0.20	0.20
Year-1		0.50	0.50	0.50
Year-0		0.30	0.30	0.30
Total		1.00	1.00	1.00
8.Discount factor		0.12	0.12	0.12
9.NPV factor		1.11	1.11	1.11
10.NPV of capital cost	Rs.million	27.89	27.89	27.22
11.Life of plant	Years	15.00	15.00	20.00
12.CRF		0.15	0.15	0.13
13.Annutised capital cost	Rs.million	4.10	4.10	3.64
14.Capital cost/KWh of power	Rs./KWh	0.70	0.70	0.63
15.Calorific Value	K.cal/NM^3			8760.00
Calorific Value	K.cal/Kg	10440.00	10440.00	
16.Heat rate for CC plants	K.cal/KWh	1767.00	1767.00	1625.00
17.N.gas consumption/KWh (gross)	NM^3/KWh			0.19
18.N.gas consumption/KWh (net)	NM^3/KWh			0.18
19.Imputed value related to capital cost	Rs/1000 NM^3			431.40
Imputed value related to fixed operating cost				
1. Fixed operating cost as % of capital cost	%	2.50	2.50	2.50
2.Total Fixed operating cost	Rs. million	0.63	0.63	0.61
3.Fixed operating cost(Rs/KWh)	Rs/KWh	0.11	0.11	0.11
4.Imputed value related to fixed operating cost	Rs/1000 NM^3			14.56
Sp. Consumption of raw materials and utilities				
Fuel Oil	T/MWh	0.17	0.17	
Natural gas	1000 NM^3/MWh			0.18

IMPUTED VALUES (FUEL OIL FIRED COMBINED CYCLE)

LOCATION: CALCUTTA

Origin	Destination	Distance (KMS.)	
Calcutta (Imported)	Calcutta	0	
Haldia (Indigenous)	Calcutta	79	
Delivered Price for Fuel Oil		Imported FO	Indigenous FO
Ex-storage price	Rs./T	3443	5896
Sales tax	Rs./T	0	2358
Excise duty	Rs./T	0	884
Customs duty & Surcharge	Rs./T	1102	0
Delivered price	Rs./T	4545	6780
Transportation cost	Rs./T	0	176
Landed Cost			
Calcutta	Rs./T	4545	6956
Cost of raw materials			
Gross	Rs/kWh	0.77	1.18
Net	Rs/kWh	0.75	1.14
Imputed value of natural gas			
Related to raw materials	Rs./1000 NM^3	4147	6347
Total Imputed value			
	Rs./1000 NM^3	4593	6793
Imputed value of natural gas			
	US$/MMBtu	**3.78**	**5.60**
Cost of generation			
	Rs/kWh	1.56	1.95
	US cents/kWh	**4.45**	**5.58**

IMPUTED VALUES (FUEL OIL FIRED COMBINED CYCLE)

LOCATION: PARADIP

Origin	Destination	Distance (KMS.)	
Paradip (Imported)	Paradip	0	
Haldia (Indigenous)	Paradip	422	
Delivered Price for Fuel Oil		Imported FO	Indigenous FO
Ex-storage price	Rs./T	3443	5896
Sales tax	Rs./T	0	2358
Excise duty	Rs./T	0	884
Customs duty & Surcharge	Rs./T	1102	0
Delivered price	Rs./T	4545	6780
Transportation cost	Rs./T	0	611
Landed Cost			
Paradip	Rs./T	4545	7392
Cost of raw materials			
Gross	Rs/kWh	0.77	1.25
Net	Rs/kWh	0.75	1.21
Imputed value of natural gas			
Related to raw materials	Rs./1000 NM^3	4147	6744
Total Imputed value			
	Rs./1000 NM^3	4593	7190
Imputed value of natural gas			
	US$/MMBtu	**3.78**	**5.92**
Cost of generation			
	Rs/kWh	1.56	2.03
	US cents/kWh	**4.45**	**5.79**

IMPUTED VALUES (FUEL OIL FIRED COMBINED CYCLE)

LOCATION: VISHAKHAPATNAM

Origin	Destination	Distance (KMS.)	
Vishakhapatnam (Imported)	Vishakhapatnam	0	
Vishakhapatnam (Indigenous)	Vishakhapatnam	0	
Delivered Price for Fuel Oil		**Imported FO**	**Indigenous FO**
Ex-storage price	Rs./T	3443	5896
Sales tax	Rs./T	0	2358
Excise duty	Rs./T	0	884
Customs duty & Surcharge	Rs./T	1102	0
Delivered price	Rs./T	4545	6780
Transportation cost	Rs./T	0	0
Landed Cost			
Vishakhapatnam	Rs./T	4545	6780
Cost of raw materials			
Gross	Rs/kWh	0.77	1.15
Net	Rs/kWh	0.75	1.11
Imputed value of natural gas			
Related to raw materials	Rs./1000 NM^3	4147	6186
Total Imputed value			
	Rs./1000 NM^3	4593	6632
Imputed value of natural gas			
	US$/MMBtu	**3.78**	**5.46**
Cost of generation			
	Rs/kWh	1.56	1.92
	US cents/kWh	**4.45**	**5.50**

IMPUTED VALUES (FUEL OIL FIRED COMBINED CYCLE)			
LOCATION: MADRAS			
Origin	Destination	Distance (KMS.)	
Madras (Imported)	Madras	0	
Madras (Indigenous)	Madras	0	
Delivered Price for Fuel Oil		Imported FO	Indigenous FO
Ex-storage price	Rs./T	3443	5896
Sales tax	Rs./T	0	2358
Excise duty	Rs./T	0	884
Customs duty & Surcharge	Rs./T	1102	0
Delivered price	Rs./T	4545	6780
Transportation cost	Rs./T	0	0
Landed Cost			
Madras	Rs./T	4545	6780
Cost of raw materials			
Gross	Rs/kWh	0.77	1.15
Net	Rs/kWh	0.75	1.11
Imputed value of natural gas			
Related to raw materials	Rs./1000 NM^3	4147	6186
Total Imputed value			
	Rs./1000 NM^3	4593	6632
Imputed value of natural gas			
	US$/MMBtu	**3.78**	**5.46**
Cost of generation			
	Rs/kWh	1.56	1.92
	US cents/kWh	**4.45**	**5.50**